The Brattle Group

The “Nemo” interconnector

Estimates of impact on TSO revenues, welfare and competition

Date: 21 February 2011

Serena Hesmondhalgh

Dan Harris

José Garcia

Prepared for National Grid and Elia

Contents

List of figures

List of tables

Disclaimer

1 Introduction and Summary

1. Elia and National Grid (the project sponsors) have commissioned The Brattle Group to estimate revenues for a 1,000 MW electrical interconnector between Belgium and Great Britain (GB) – hereafter referred to as the 'Nemo' interconnector or simply Nemo.

2. We have used our proprietary Brattle Annual Model (BAM) to simulate the operation of the electricity markets of GB, Belgium, France, the Netherlands and Germany,[1] and have validated BAM by performing a backcast of 2009 prices. We have modelled electricity prices and interconnector revenues for three future years: 2020; 2025 and 2030. The model can provide two different estimates of value; a deterministic value, where the input parameters are fixed; and a probabilistic value, where three of the main input parameters – generation from wind, demand and plant outages – are drawn at random from distributions. Whilst deterministic runs are relatively quick to perform, the probabilistic results are likely to be more realistic, since they include the types of random effects that create price differences and interconnector value in the real world. Accordingly we have concentrated on probabilistic analyses of Nemo.

3. We assume that the Nemo interconnector has a capacity of 1,000 MW, and that transmission losses are 3%. We do not assume any down-time – planned or forced – for the interconnector so our revenue projections may slightly over-estimate what could be achieved in practice. Note also that all monetary values are reported in 2009 money unless otherwise stated.

4. In all the scenarios and sensitivities we assume that the owners of new baseload plants will fully recover their fixed (mainly capital) costs in the long-run. However, new peak plants are assumed to recover only 75% of their fixed costs. Because peak plants do not recover all of their fixed costs in the model, peak prices are lower than they would be with 100% cost recovery for peak plant, and so price differences and interconnector revenues are also lower. However, since we are seeking to capture long-run equilibrium values, we consider that it is more realistic to assume that peaking plant cannot cover all their capital costs as such cost recovery is likely to be concentrated into a relatively small number of years.

5. It is important to highlight two aspects of the modelling which are important when interpreting the results. First, the model assumes that all interconnector capacity is dedicated to market coupling. In reality today, some interconnector capacity is still sold via explicit auctions. Since the revenues from capacity sold by auction can be significantly less than those achieved by market coupling, if all the capacity of an interconnector is sold in this manner, particularly if the auctions take place well in advance,[2] the revenues predicted by the BAM model, assuming 100% market coupling, may be higher than the congestion rents observed historically. Second, the BAM model captures all price differences up to real time despatch. In contrast, day-ahead market coupling will only capture the effects of events which happen up to day-ahead gate closure. For example, if a plant in Belgium fails 4 hours before its scheduled despatch, this could create a price difference that will be counted towards congestion rents by BAM. However, such a plant failure would have no effect

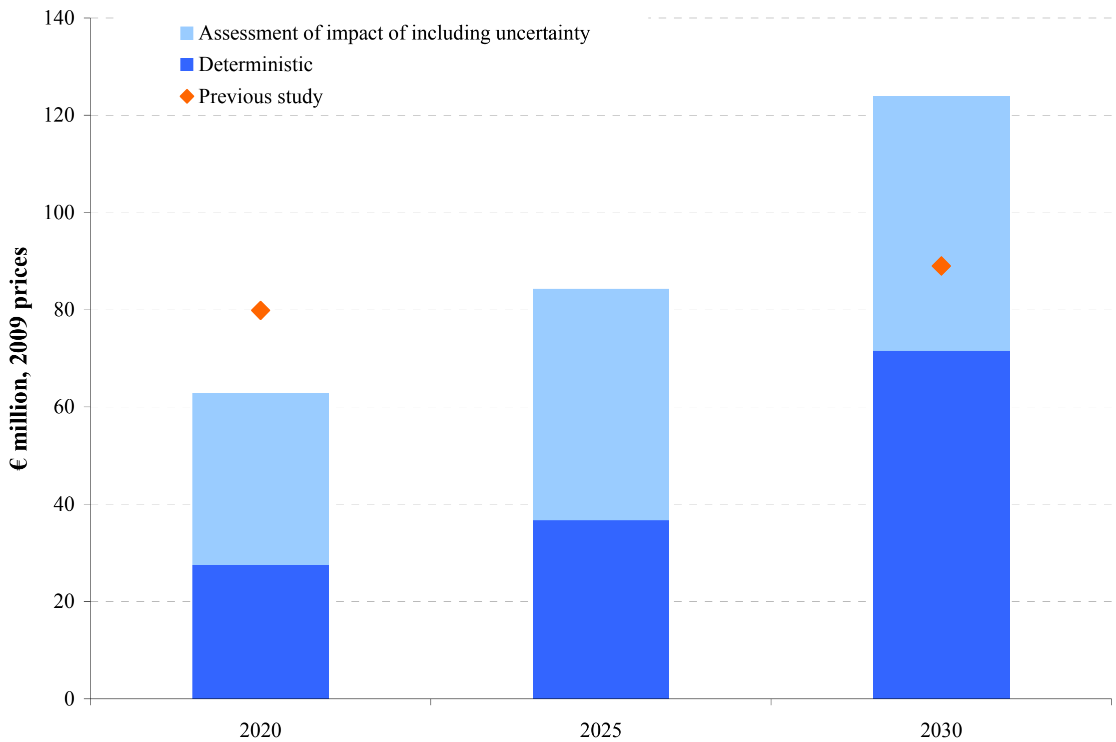
[1] We have also performed some sensitivities where we also model Switzerland, Italy and Austria in detail.

[2] The extent of the difference depends on how predictable the direction of flows is likely to be.

on day-ahead prices which are already fixed, and so would not currently affect congestion rents. Accordingly, BAM predicts the maximum possible congestion rents, assuming 100% market coupling and intra-day trading close up to real time despatch. Such a market design is not implemented at present. However, initiatives that are currently underway, such as market coupling, will move EU markets towards the BAM position. Moreover, our backcasting indicates that for interconnectors from GB, the BAM results match the historical data quite closely (see Appendix IV for details). For other interconnectors the gap between the BAM results and the historical data is wider, and so we make a downward adjustment to the congestion rents to account for this.

6. Figure 1 illustrates the median incremental interconnector revenues for the probabilistic base case in real (2009 price) terms. Figure 1 illustrates the deterministic congestion rents and the probabilistic congestion rents for the Nemo interconnector. The probabilistic congestion rents are about €60 million in 2020, and increase to over €100 million by 2030, even in real terms. This is primarily due to the increase in the wind plant capacity over time mainly in GB, both in absolute terms and as a percentage of installed capacity. Because the output from wind plants is intermittent and not perfectly correlated between GB and Belgium, additional wind plant capacity creates price differences that generate additional interconnector value. We have also compared the results to a previous 2006 study on the Nemo cable.[3] Because peak cost recovery is lower in the current study than in the previous one, 2020 revenues are lower in this study than in the previous study. On the other hand, the current study assumes much higher levels of GB wind, and so this more than offsets the lower capital cost recovery by 2030.

Figure 1: Adjusted median probabilistic Nemo Cable revenues

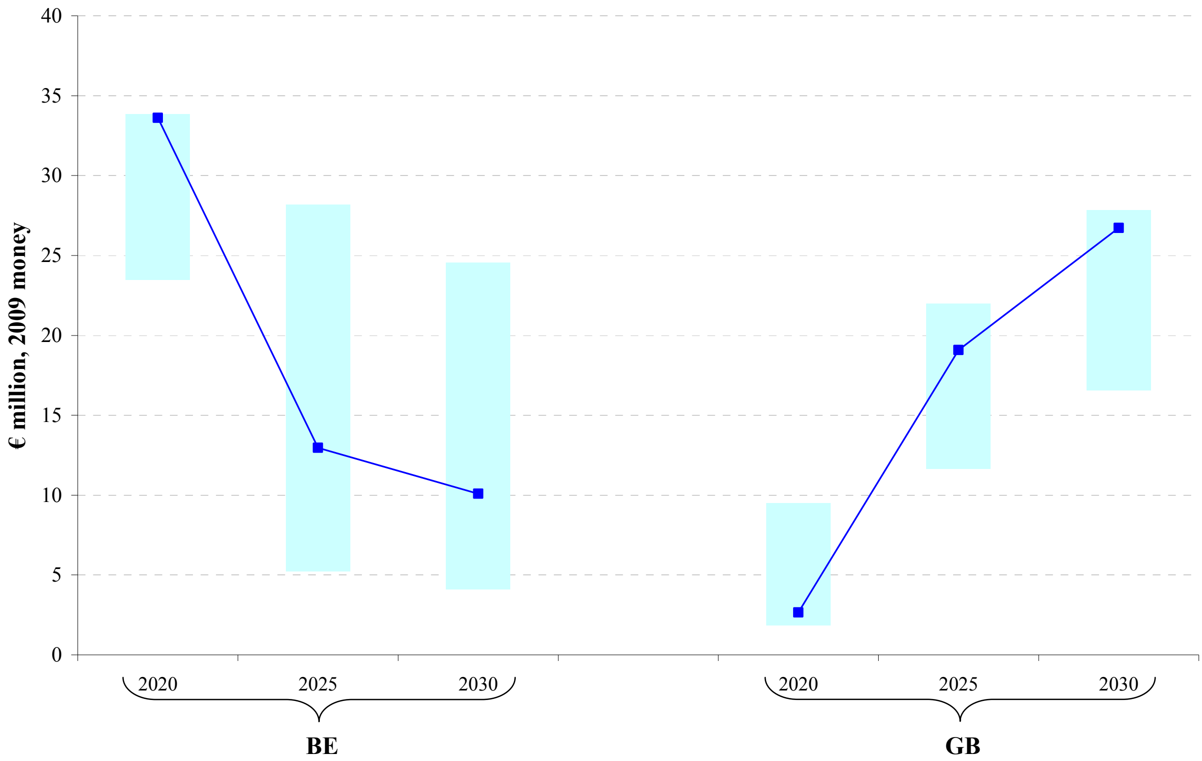


[3] The final report for this study was published in January 2007.

7. Figure 2 shows the median change in overall welfare as a result of the Nemo interconnector, for GB and Belgium. We calculate the change in overall welfare from (a) the change in prices multiplied by the domestic demand (consumer welfare) and (b) the change in prices multiplied by the change in generation output (producer welfare). The blue line in Figure 2 shows the results for the base case, and the bars illustrates the range of welfare changes resulting from the scenarios and sensitivities modelled. We describe these scenarios below.

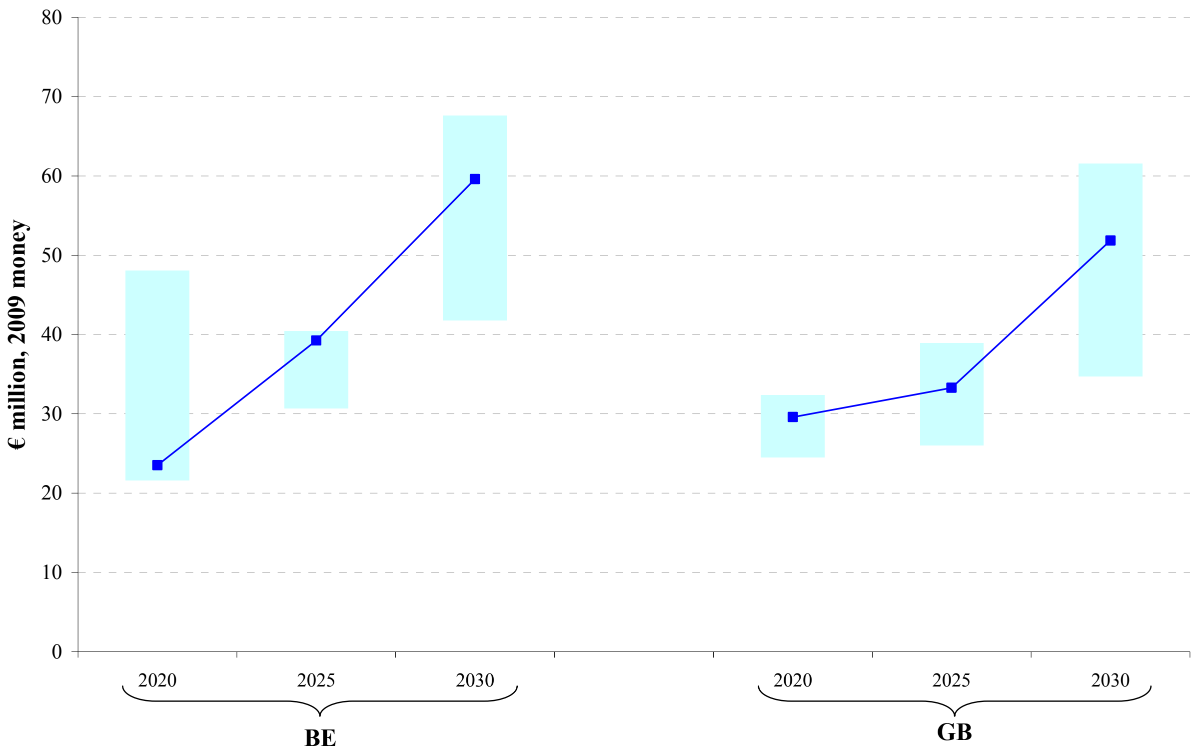
8. The changes in welfare correspond to changes in price levels due to the Nemo interconnector. If prices go up for a given country, producer welfare will go up and consumer welfare will go down, and vice versa if prices fall as a result of the Nemo interconnector. Initially, Belgium makes the biggest net gain from the interconnector project, but then the increases in GB become larger and the Belgian welfare gain reduces. However, we think it is not correct to think of this as a trend that will continue. Rather, the period 2020 to 2030 represents a transition a more sustainable lower carbon generating park. This transition is largely complete in 2030, and so the 2030 welfare results are more likely to represent an equilibrium.

Figure 2: Median net change in overall welfare for GB and BE as a result of a 1,000 MW Nemo interconnector



9. The revenues collected by the TSOs in both GB and Belgium (measured as 50% of the congestion revenues across all the modelled links for each country) increase as a result of the cable. This is despite the fact that congestion revenues on other borders fall when the cable is included. The additional congestion revenues associated with the Nemo cable outweigh these losses. Again the line shows the results for the base case, and the bars illustrate the range of welfare changes resulting from the scenarios and sensitivities modelled.

Figure 3: Adjusted median probabilistic changes in TSO revenues as a result of the Nemo cable

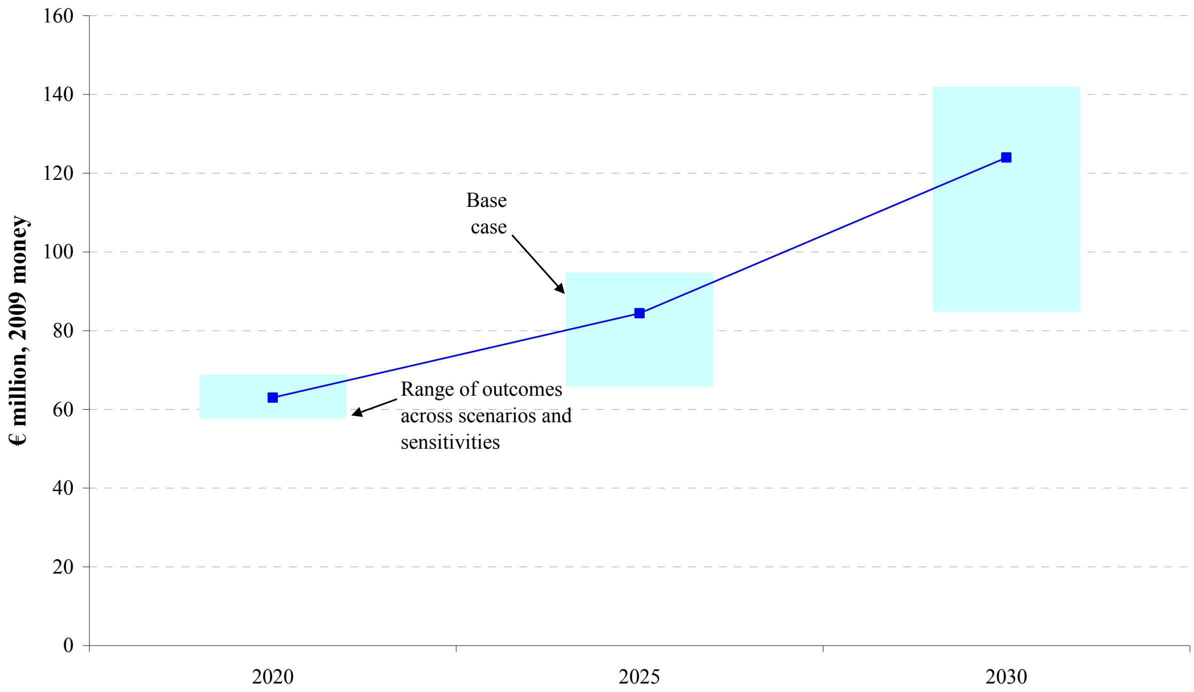


10. We have investigated the effects on the congestion rents and welfare of a number of scenarios and sensitivities:

- Scenario 1: coal prices increased so marginal coal and gas costs are broadly equal
- Scenario 2: lower wind capacity but overall capacity margin maintained
- Scenario 3: combination of scenarios 1 and 2
- Scenario 4: nuclear lifetimes extended to 50 years in Germany
- Sensitivity 1: increased onshore wind in BE, with reduced biomass capacity
- Sensitivity 2: reduced interconnector capacity
- Sensitivity 3: cold winter case i.e. increased winter demand for Belgium, France and Germany

11. Figure 4 shows the range of the resulting congestion rents from the scenarios, while Figure 2 above shows the range of welfare outcomes. There are no scenarios which we model that result in a very significant drop in interconnector revenues. Because random variations in wind power create price differences across the interconnector, scenarios which involve more wind power increase congestion revenues, and scenarios with lower wind power reduces revenues. A scenario with high coal prices (or equivalently higher carbon prices) tends to increase GB off-peak prices and reduce price differences and hence congestion rents across the Nemo interconnector.

Figure 4: Median congestion rents



12. We have reviewed the implications for this study of the UK government's latest proposals for the GB electricity market.[4] We conclude that the proposed feed-in tariffs would make little difference to the way in which we already model low-carbon generation, including nuclear power. We find that the carbon floor proposal and the reserve contract proposals are likely to counteract each other: the carbon floor proposal could push peak prices up whilst reserve contracts could reduce them. It is difficult at this stage to predict what the overall effect will be but it is likely that any impact would be greater for flows than for congestion rents. In other words, even if the direction of net flows changed this would not necessarily result in reduced congestion rents, since these depend only on the absolute difference in prices.

13. The project sponsors also asked us to assess the competitive effect of the Nemo interconnector, on both the GB and Belgian electricity markets. We conclude that Nemo is likely to enhance competition in both the Belgium and the GB market. However, at present we do not know how much capacity could be bought by explicit auction, and how much would be allocated by implicit auction. An explicit auction raises the possibility that a party could obtain capacity in the cable and subsequently exercise market power. Accordingly, it may be necessary to impose limits on the capacity that a company can control as a result of explicit auctions. In the most pessimistic case, where we assume that any new capacity not already under construction or at an advanced state of development is allocated to the largest generator in a market, we find that the largest generator in Belgian market (Electrabel) should not be allowed to control more than 55% (550 MW) of the capacity of the Nemo cable. Similarly, the largest generator in the GB market (RWE) should not control more than 41% (410 MW) of the capacity in the Nemo cable.

[4] 'Electricity market reform, Consultation document', December 2010, Department of Energy and Climate Change.

2 The BAM model and main inputs

14. We have used our proprietary Brattle Annual Model (BAM) to generate prices for 2020, 2025 and 2030 and the congestion rents on interconnectors. The BAM model is essentially a simple despatch model, which calculates the system marginal prices and cross-border flows based on plant data, fuel prices *etc*. Unlike some more complicated models, it does not predict the level of market power, or the increase in generator offer prices above marginal costs – the model user must input these parameters. On the other hand, this kind of despatch model is simple, transparent, relatively easy to understand, and creates unique solutions.

15. To reduce computation time, rather than modelling all days in a year BAM uses representative or characteristic days. Specifically, BAM uses a characteristic weekday, a peak weekday, Saturday and Sunday for each month of the year, so that 48 characteristic days are modelled for each year in total. A full 24 hours are modelled for each characteristic day. The main outputs of the BAM model are the prices in each country, the flows between countries, and the costs, revenues and profits of each plant. BAM does not explicitly include start-up costs, since this would considerably increase the computational time of the model, but their impact can be mimicked by the use of market power add-ons for particular half-hours. (Specifically, we recognise that overnight prices are often below marginal costs as generators seek to ensure that their plants are not switched off and hence we include negative mark-ups in these hours.)

16. Due to the high degree of interconnectivity in north-west Europe, as well as modelling the GB and Belgian electricity markets we have also modelled Germany, France, and the Netherlands. Countries outside of the model are accounted for by assuming that either flows to and from the countries modelled in detail remain at their historical levels (Austria, Switzerland, Italy and Spain) or that prices in the external country move from their historic levels in line with the marginal costs of coal plants (NordPool, Poland, the Czech Republic).

2.1 Main inputs

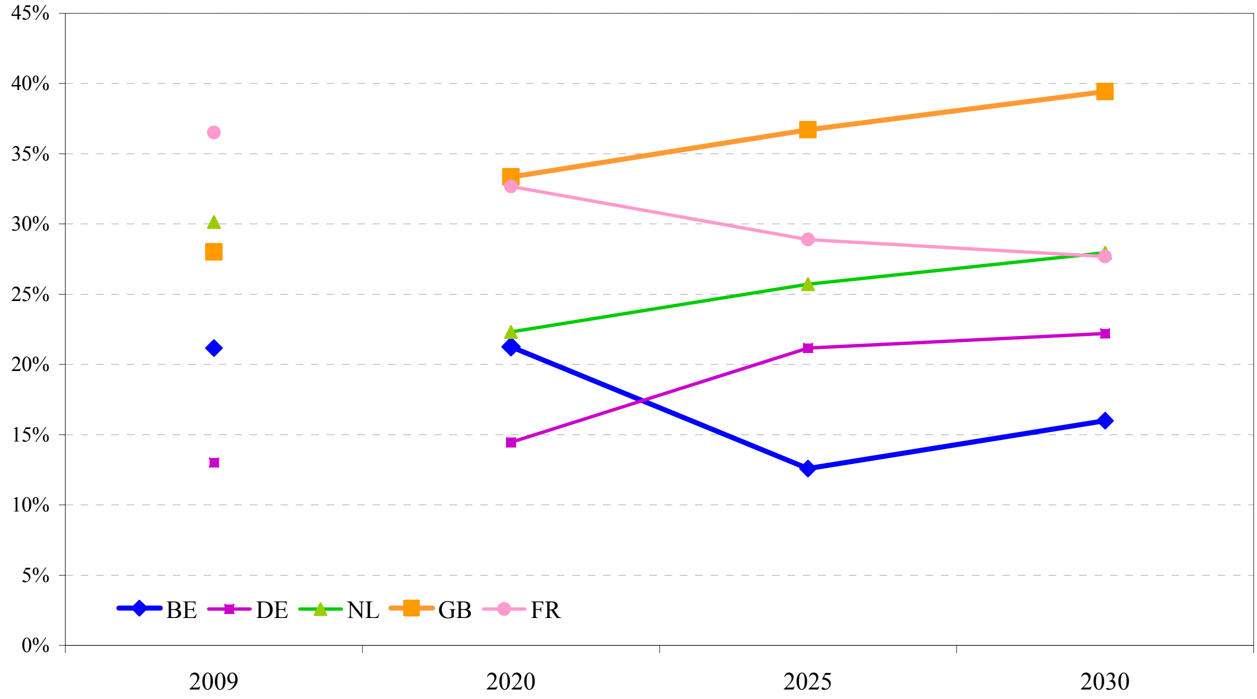
17. The main inputs to the BAM model are: a list of installed plants in each country, details such as the capacity of the plant, fuel type, thermal efficiency *etc.*; the cost of the fuels used to generate electricity; demand in each country; and the capacity of interconnection between countries. The project sponsors have provided us with guiding assumptions for most of these inputs.

18. With respect to installed capacity, we have matched the project sponsors' estimates for the total capacity of installed plant by type over the period modelled. National Grid supplied data for GB, and for other countries we used data provided by Elia. Importantly, this means that we assume nuclear lifetimes of 40 years in Belgium, except for some older nuclear plants the life time of which is extended to 50 years. To model plant outages realistically we have broken down the aggregated total of plant types into individual plants. Our base case assumes that all countries modelled meet their estimated 20/20/20 targets for electricity generated from Renewable Energy (RE).

19. The project sponsors have provided us with a forecast of both peak demand (GW) and volume of demand (TWh), which we match. We derive a more detailed load shape from hourly 2009 demand. We then apply a growth rate to the 2008 demand so that demand meets the forecasts peak load and volume. Figure 5 below shows the capacity margins that result from combining the sponsors' demand and capacity assumptions. These capacity margins measure the difference

between installed capacity and peak demand as a function of peak demand, except that for wind and solar plants, the installed capacity has been de-rated to reflect their typical maximum output at peak demand (20% for onshore wind and 25% for offshore wind,[5] 0% for solar). The low 2025 Belgian capacity margin has relatively little impact in the deterministic analysis. It will tend to lead to off-peak prices that are higher than would otherwise be the case but since our analysis concentrates on measuring the change from adding the cable rather than absolute results, it is unlikely to have a major impact.[6]

Figure 5: Capacity margins in the base case



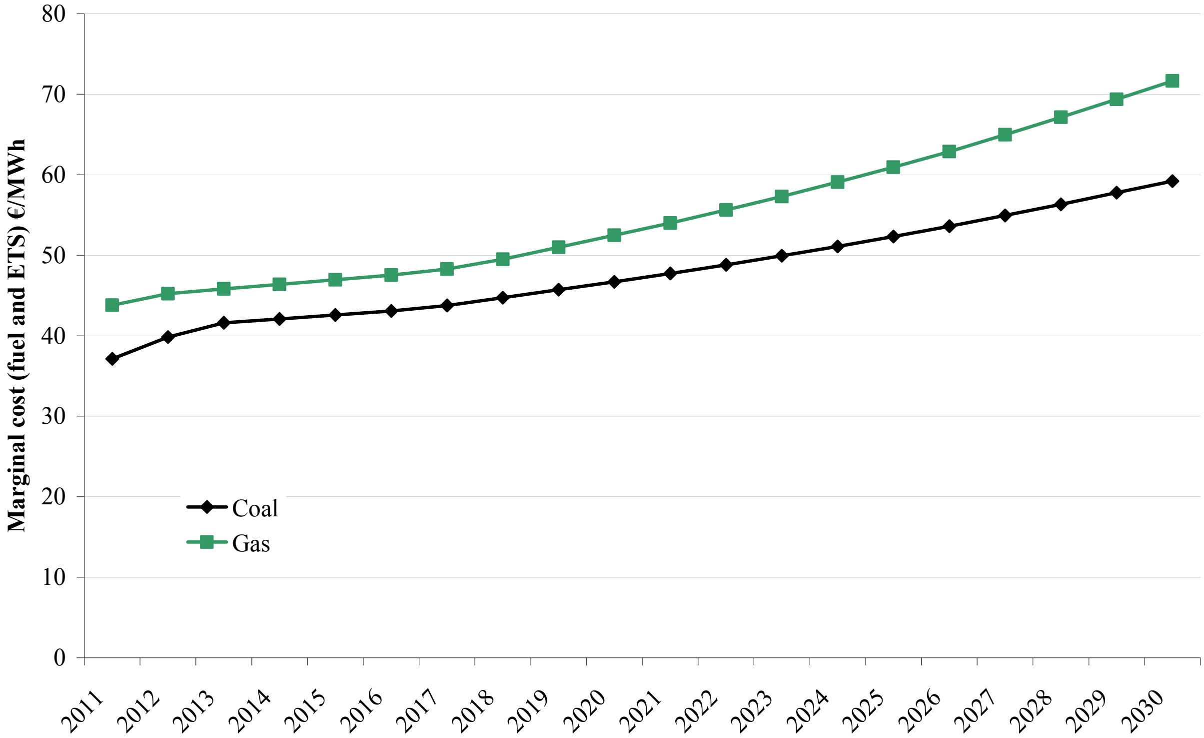
20. At the instruction of the project sponsors, we assumed that fuel prices are the same in all countries modelled, apart from transportation costs. In other words, we do not capture interconnector value that may arise from transitory differences in fuel prices, and hence our results will tend to underestimate interconnector revenues. Specifically for gas prices, we based the price differences on the difference in the cost of shipping LNG from the middle-east to the various countries modelled. The average delivered gas price equals the indicative price forecast the project sponsors provided. We also assume that gas prices have the same seasonal pattern for all markets, being higher in winter than in the summer. Figure 6 illustrates the resulting (representative) marginal cost of gas and coal-fired plant, on an annual average basis, over the period modelled.

---

[5] Except in Germany, where the equivalent figures are 10% and 15%.

[6] The effect may be somewhat more significant for the probabilistic analysis where forced outages are modelled stochastically – a plant is either fully available or unavailable – rather than by de-rating the typical available capacity of the plant. Nonetheless, the results suggest that the impact is limited because the increase in Belgian prices over time is not significantly different to that for other countries.

Figure 6: Representative marginal costs, nominal, including carbon costs, for gas and coal-fired plant[7]



21. We have agreed with the project sponsors that the base case should represent a long-run equilibrium (LRE) – that is, new baseload plants are able to recover all of their costs but that, on average, new peaking plants can only recover 75% of their fixed costs. Adopting a base case which is consistent with a LRE seems sensible for such a long term project as the Nemo interconnector. In BAM, the timing of cost recovery is driven largely by demand. Specifically, generators – especially peaking plants – will recover nearly all their fixed and capital costs during the 10% of hours with the highest demand. As these demand, and price, peaks occur at different times in the GB and Belgian markets, cost recovery creates large price differences between GB and Belgium in some hours. In 2020 and 2025, this means that the interconnector earns most (80%) of its revenue over a relatively small number of hours (15%-20%). To the extent that, in practice, fixed cost recovery is more spread out and takes place at different times in different countries due to uncorrelated plant failures, our approach is conservative in the sense that it is likely to underestimate congestion rents. Moreover, by 2030, revenues are earned over a much wider range of hours due to the frequency of very low or zero prices in GB.

2.2 Modelling renewable generation

22. Wind and, to a lesser extent, solar power become particularly significant for estimating Nemo interconnector revenues by 2030. This is for two reasons. First, the capacity of installed renewable energy becomes very significant. For example, by 2030 the model assumes 36 GW of wind power in GB, about 35% of installed capacity. Second, electricity production from wind and solar

---

[7] Assumes 60% efficient gas plant and 42% efficient coal plant. Note that in the model plant efficiencies vary with plant age.

sources is intermittent, resulting in price volatility and the opportunity for price differences to arise across the interconnector.

23. We model random (probabilistic) wind fluctuations in our probabilistic analysis. In the deterministic modelling, we assume an average profile for wind and solar power. The profile assumes a different 'capacity factor'[8] for each hour of each month. We derive the wind profile for each country based on actual wind speed data for that country (Appendix V gives more details of our approach to deriving electricity generation from wind speed data). We make an adjustment for higher average load factors for offshore wind. We have derived hourly capacity factors for solar based on the European Commission's Photovoltaic Estimation Utility. This tool gives the estimated electricity generation from a solar (Crystalline silicon) panel for any location in Europe per month and for each hour of the day for a specific month.

24. The EU has made a commitment for 20% of its energy to come from RE sources by 2020. Each Member State has its own target for the percentage of its energy it will derive from RE sources by 2020. The target includes transport and sectors other than power generation, and so does not translate directly into a target for the percentage of electricity that should be generated from RE sources. However, some countries have translated their 2020 target into percentage of electricity that should be generated from RE sources. Based on these numbers, we have derived a percentage of electricity that should be generated from RE sources for all countries modelled. All countries meet this RE target in the base case.

[8] The capacity factor is the actual production of electricity in an hour divided by the maximum possible production. For a 1 MW wind turbine, a capacity factor of 10% in a particular hour means the turbine produced 0.1 MWh in that hour.

3 Base case results

3.1 Methodology

25. To produce the probabilistic results, we run the BAM model for each year about 100 times. In these runs, we model each day of the year separately, rather than using characteristic days. For each run and for each hour, the model picks random values for:

- Wind power output (all countries);
- Demand (Belgium, France, Germany and the Netherlands);
- Unplanned plant outages (all countries).

26. We account for correlations between wind output and demand for the countries modelled but plant outages are assumed to be independent. Appendix V describes the main assumptions and methodology for the probabilistic modelling in detail.

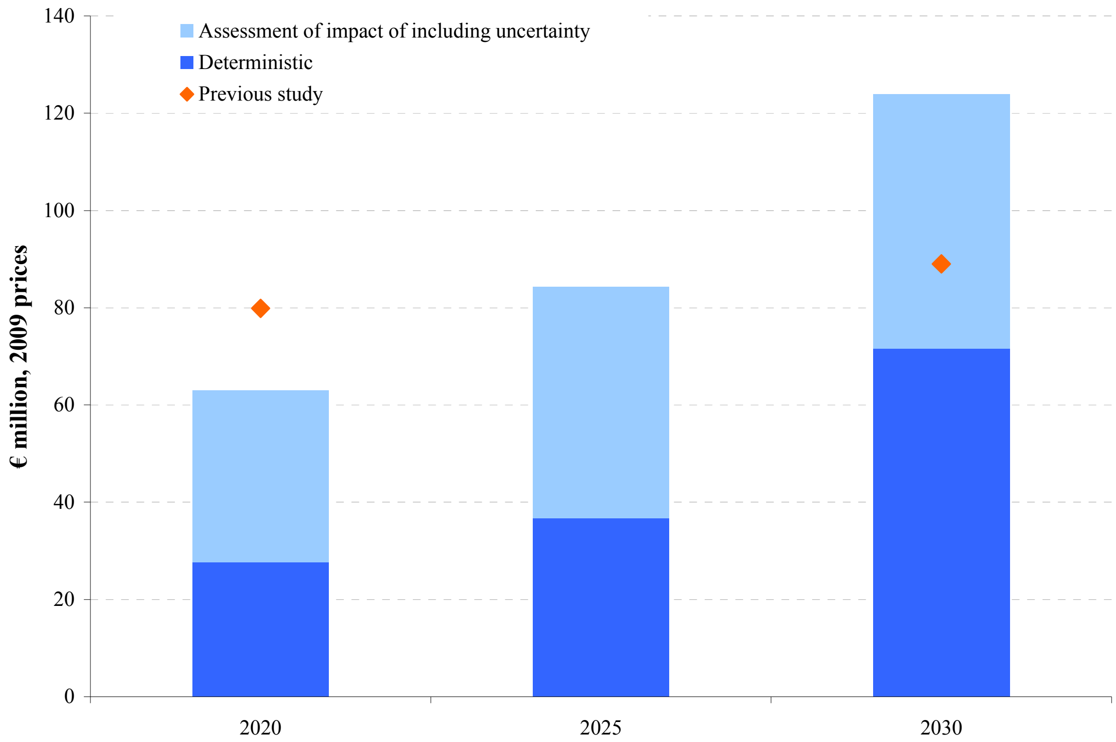
3.2 Congestion rents

27. Figure 7 shows the median congestion rents on the Nemo interconnector for the probabilistic runs.[9] It illustrates that both the deterministic and probabilistic rents increase over time in real terms, with the probabilistic rising from €60 million in 2020 to about €120 million in 2030. The figure breaks the revenues down into revenues which would occur even if all the inputs were fixed – deterministic revenues – and the revenues which arise because of the random events which we model. To the extent that they are not correlated, random events such as unexpected demand changes, plant outages and changes in generation from wind farms should increase the value of the Nemo interconnector; a deviation from the average value for these parameters at one end of the interconnector but not the other will generally create larger price differences across the interconnector relative to a deterministic run. For example, in the deterministic case plant outages are dealt with by reducing the output of each plant for its expected failure rate – a 100 MW plant with a 3% expected failure rate will be modelled as a 97 MW plant. In a probabilistic run, the plants will either be running at full capacity, or they will fail. This means that one country could have no failures, and a neighbouring country could experience the failure of two large plants. This will create a greater price difference between the two countries than if both countries are running at their average outage level. Note that the inputs (plant type and margin, fuel prices, plants costs *etc.*) to the probabilistic and deterministic base cases and scenarios are identical.

28. The (real) increase in probabilistic congestion rents between 2020 and 2030 is primarily due to the increase in the wind plant capacity, particularly in GB, both in absolute terms and as a percentage of installed capacity. Because the output from wind plants is intermittent and not perfectly correlated between GB and Belgium, additional wind plant capacity creates price differences that generate additional interconnector value.

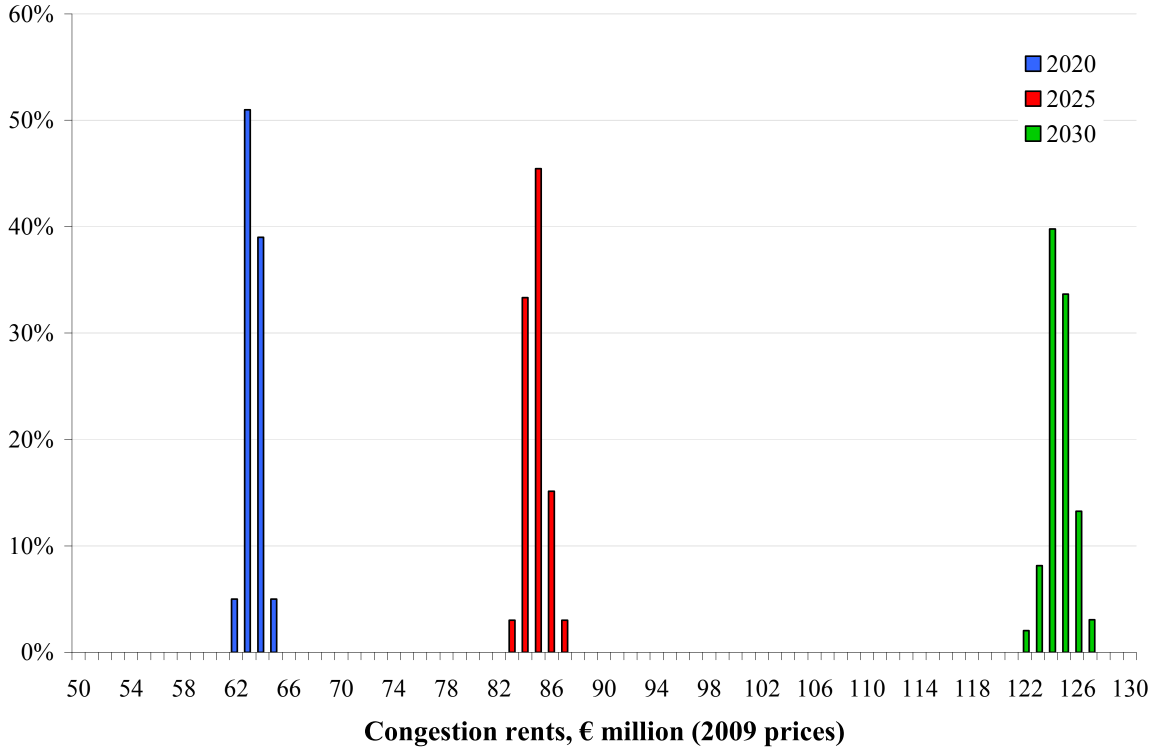
[9] We assume 2% inflation per year to convert between real and nominal prices.

Figure 7: Base case median Nemo interconnector congestion rents



29. Figure 8 illustrates the distribution of interconnector rents, rather than just the median values. Because of the increased wind capacity and increased variation in prices, the congestion rents are more broadly distributed in 2030.

Figure 8: Base case distribution of Nemo interconnector congestion rents



30. It is important to highlight two aspects of the modelling which are important when interpreting the results. First, the model assumes that all interconnector capacity is dedicated to market coupling. In reality today, some interconnector capacity is still sold via explicit auctions. Since the revenues from capacity sold by auction can be significantly less than those achieved by market coupling, the revenues predicted by the BAM model, assuming 100% market coupling, may be higher than the congestion rents observed historically. Second, the BAM model captures all price differences up to real time despatch. In contrast, day-ahead market coupling will only capture the effects of events which happen up to day-ahead gate closure. For example, if a plant in Belgium fails 4 hours before its scheduled despatch, this could create a price difference that will be counted towards congestion rents by BAM. However, such a plant failure would have no effect on day-ahead prices which are already fixed, and so would not currently affect congestion rents. Accordingly, BAM predicts the maximum possible congestion rents, assuming 100% market coupling and intra-day trading close up to real time despatch.

31. Such a market design is not implemented at present. However, initiatives that are currently underway, such as market coupling, will move EU markets towards the BAM position. Consequently, in the future there is an increased likelihood that unadjusted BAM estimates will match real market observations as market integration increases.

32. Nevertheless, to ensure that we adopt a conservative approach, i.e. do not over-estimate the benefits of the interconnector, we adjust our results for congestion revenues and TSO revenues via a two step process. First we compare the congestion rents of the 2009 probabilistic backcast to the rents that would have occurred, if all of the interconnector capacity had been used for market coupling. We actually find close agreement between backcast results for interconnectors from GB. Therefore we do not make any adjustments for the results from interconnectors from GB, including Nemo. For non-French, non-GB borders, our backcast BAM congestion rents are, on average, about 40% higher than our estimated actual congestion rents. Whilst this average is achieved from two very different results, it is conservative to apply it to all non-French, non-GB borders. Accordingly, in the second step we reduce the probabilistic congestion rents forecast by BAM by about 40%. For France, the reduction is higher at 128% because, as we discuss below, there are other special factors that make forecast congestion rents for connections on the French border especially high.

33. In Figure 9 and Table 1 we show the change in the congestion rents of other interconnectors modelled. The Nemo interconnector reduces the rents from all the other cables.

Figure 9: Base case median changes in congestion rents for other interconnectors

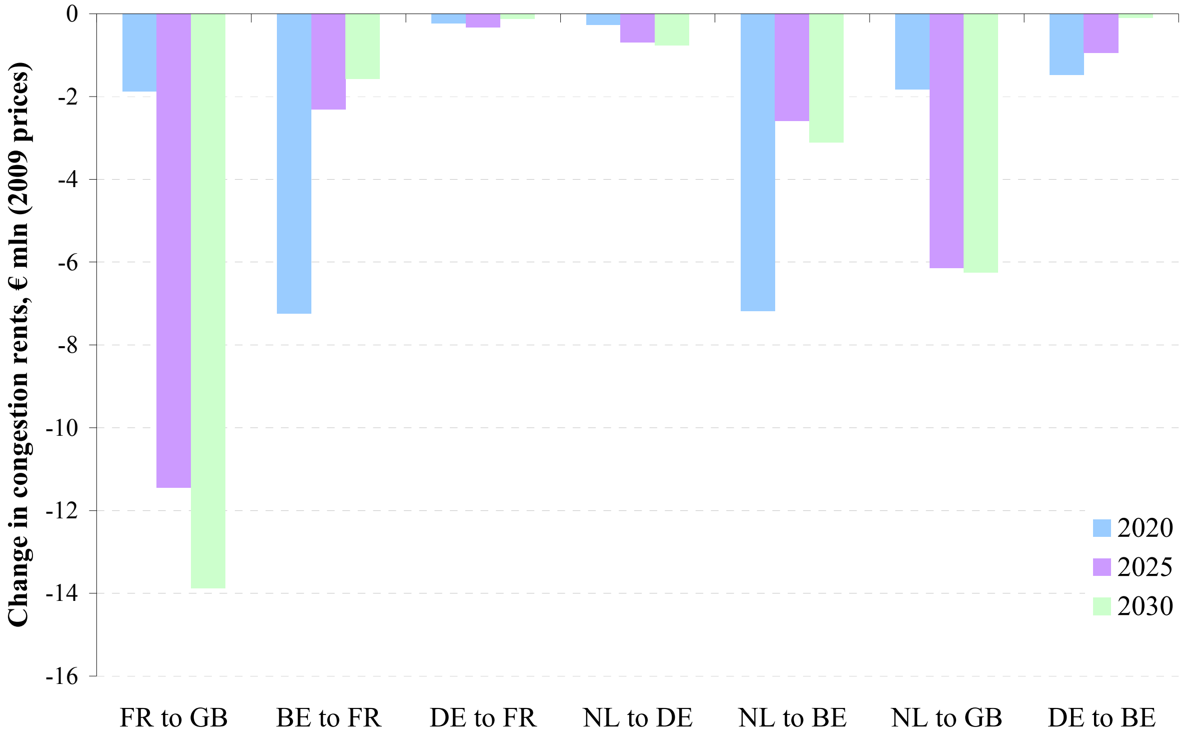
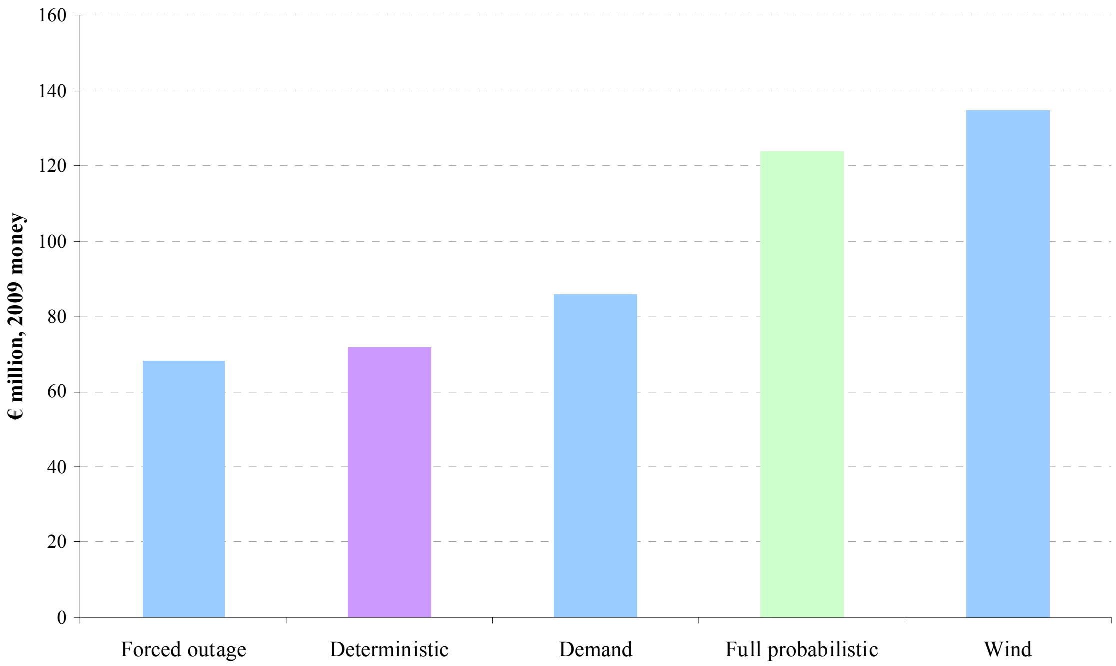


Table 1: Base case median congestion rents, € million, 2009 money

	With GB-BE cable			Without GB-BE cable			Change (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
FR to GB	253.7	363.9	481.5	255.6	375.6	495.5	-1.9	-11.5	-13.9
BE to FR	84.7	132.7	177.6	92.0	135.0	179.2	-7.3	-2.3	-1.6
DE to FR	102.9	148.1	187.2	103.1	148.5	187.3	-0.2	-0.3	-0.1
NL to DE	197.4	215.6	229.2	197.7	216.4	230.0	-0.3	-0.7	-0.8
NL to BE	51.7	69.1	79.9	58.9	71.7	83.0	-7.2	-2.6	-3.1
NL to GB	59.9	81.6	119.0	61.8	87.8	125.3	-1.8	-6.1	-6.2
DE to BE	46.7	51.5	55.3	48.2	52.5	55.3	-1.5	-1.0	-0.1
GB to BE	63.0	84.4	124.0	0.0	0.0	0.0	**63.0**	**84.4**	**124.0**
Total	860.0	1147.0	1453.7	817.3	1087.5	1355.5	42.7	59.5	98.1

34. In Figure 10 we have investigated the contribution that each source of randomness makes to the probabilistic congestion rents for the Nemo. We did this by running the model for 2030 including each source of randomness separately. Running the model with only random forced outages actually very slightly reduces congestion rents relative to the deterministic case, where all the inputs are fixed. This reflects that difference between using constant de-rating and an on/off approach to forced outages. Including only random demand increases congestion rents modestly relative to the deterministic case whilst running the model just with random wind variation creates the largest congestion rents. Running the model with random wind, demand and plant outages reduces congestion rents relative to the random wind only case, since some of the random effects cancel one another out. The exercise demonstrates that random wind variations are the most important contributor to congestion rents.

Figure 10: The relative contribution of different sources of randomness to probabilistic congestion revenues for the base case in 2030



3.3 TSO revenues and cross-border flows

35. Table 2 shows our estimates of the revenues earned from cross-border flows by the GB and BE TSOs – both with and without the adjustments described in the preceding section. Of course, as we do not make an adjustment to interconnectors connected to GB, there is no difference between adjusted and unadjusted flows for the GB TSO. These values have been calculated on the basis that congestion rents are shared equally between the TSOs on each side of a border. The change in the unadjusted TSO revenues is calculated as the median of the differences in the revenues for each iteration and, for this reason, it may not exactly match the difference in the median revenues under the two cases. However, the change in the adjusted TSO revenues is calculated directly from the adjusted median revenues under the two cases. Figure 11 and Figure 12 show the distributions for the change in TSO revenues in BE and GB respectively. Note that these figures are based on *unadjusted* revenues – equivalent figures for BE adjusted revenues would have the same shape but in 2020 would be shifted up by around €6 million. (In the other two years, the change in the BE adjusted and unadjusted revenues are almost identical.)

Table 2: Base case median TSO revenues for BE and GB, € million (2009 money)

	With GB-BE cable			Without GB-BE cable			Change (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Unadjusted									
BE	197.5	278.7	359.9	180.5	241.6	301.9	17.1	38.8	60.1
GB	188.3	265.0	362.3	158.7	231.7	310.4	29.6	33.3	51.9
Adjusted									
BE	123.0	168.9	218.4	99.5	129.6	158.7	23.5	39.2	59.6
GB	188.3	265.0	362.3	158.7	231.7	310.4	29.6	33.3	51.8

Figure 11: ***Base case*** **distribution of change in Belgian TSO revenues as a result of the Nemo interconnector**

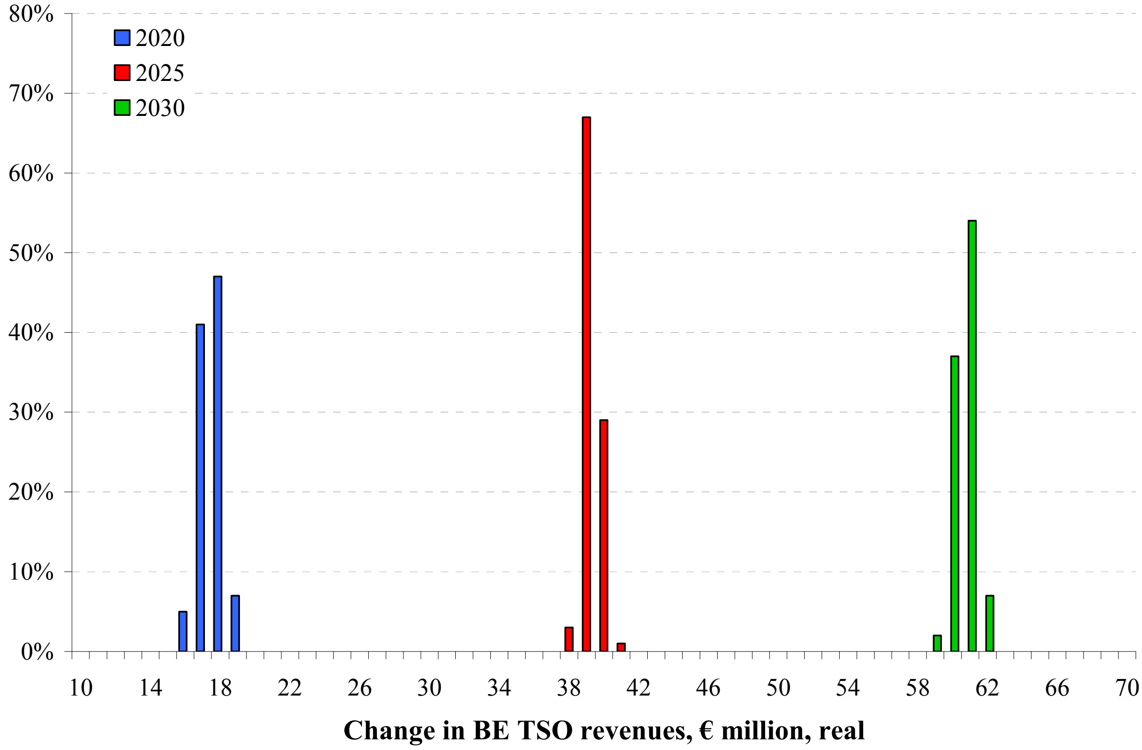
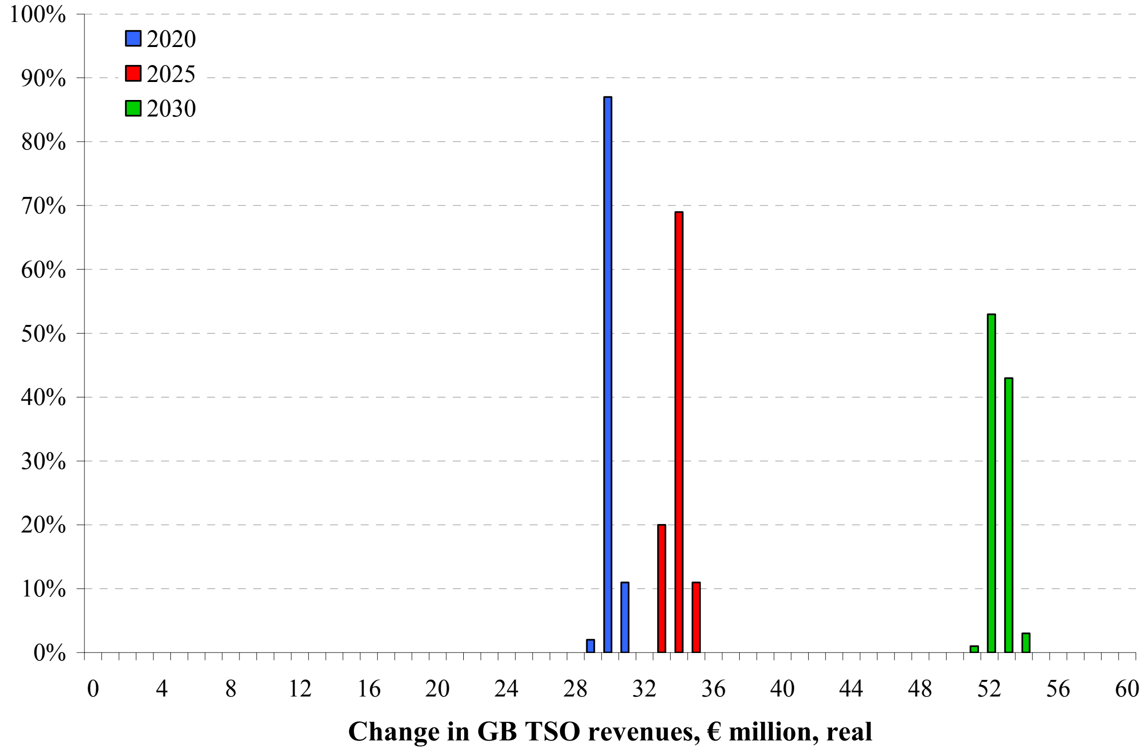
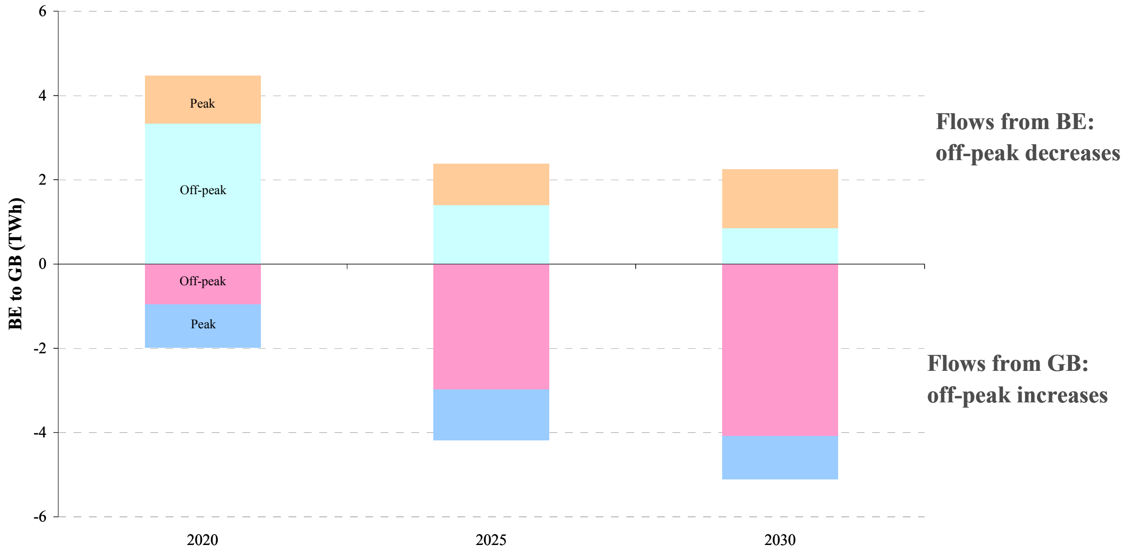


Figure 12: ***Base case*** **distribution of change in GB TSO revenues as a result of the Nemo interconnector**



36. Figure 13 illustrates the cross-border flows (in both directions) across Nemo interconnector. In 2020 GB off-peak prices are slightly higher than Belgian off-peak prices, primarily because we assume a decline in GB nuclear capacity, and this encourages off-peak power to flow from Belgium to GB. Over time, the addition of more renewable energy, especially wind, in the GB market causes a large fall in off-peak GB prices. By 2030, GB off-peak prices are about €11/MWh lower than Belgian off-peak prices. As a result, there are large off-peak flows from GB to Belgium during these hours.

Figure 13: Base case median flows across Nemo



37. Table 3 shows the flows across all the cases studied, with and without the Nemo cable. It shows that generally speaking the Nemo cable only has a very modest impact on the flows across other interconnectors.

Table 3: *Base case* median cross-border flows, TWh

With GB-BE cable

From:	To: FR	BE	DE	NL	GB	Total exports
2020						
FR		14.6	12.9		15.9	43.4
BE	7.1		4.4	6.9	4.5	22.8
DE	3.5	4.4		16.4		24.3
NL		5.8	4.2		4.5	14.5
GB	6.2	2.0		2.3		10.5
Total imports	16.7	26.8	21.5	25.6	24.8	
2025						
FR		14.9	13.7		11.0	39.5
BE	6.7		4.7	6.2	2.4	20.1
DE	9.2	4.0		19.2		32.4
NL		6.4	23.4		2.6	32.4
GB	11.4	4.2		4.3		19.9
Total imports	27.3	29.5	41.8	29.7	16.0	
2030						
FR		15.8	14.5		10.2	40.6
BE	6.0		4.8	6.3	2.3	19.3
DE	8.3	4.0		19.3		31.5
NL		6.3	23.2		2.4	31.9
GB	12.8	5.1		5.2		23.1
Total imports	27.0	31.2	42.6	30.8	14.9	

Without GB-BE cable

From:	To: FR	BE	DE	NL	GB	Total exports
2020						
FR		14.4	13.0		15.8	43.1
BE	7.2		4.5	7.1	0.0	18.7
DE	3.5	4.3		16.5		24.3
NL		5.6	4.2		4.4	14.2
GB	6.2	0.0		2.4		8.6
Total imports	16.9	24.3	21.7	26.0	20.2	
2025						
FR		14.9	13.7		10.9	39.5
BE	6.7		4.7	6.1	0.0	17.5
DE	9.2	4.1		19.2		32.5
NL		6.6	23.4		2.7	32.6
GB	11.6	0.0		4.3		15.9
Total imports	27.4	25.5	41.8	29.7	13.6	
2030						
FR		15.8	14.5		10.4	40.6
BE	6.0		4.8	6.3	0.0	17.2
DE	8.3	3.9		19.4		31.6
NL		6.3	23.1		2.6	32.0
GB	12.7	0.0		5.0		17.7
Total imports	27.0	26.0	42.4	30.8	13.0	

Difference (with minus without)

From:	To: FR	BE	DE	NL	GB	Total exports
2020						
FR		0.2	0.0		0.1	0.2
BE	-0.1		-0.1	-0.2	**4.5**	4.1
DE	0.0	0.1		-0.1		0.0
NL		0.3	0.0		0.1	0.3
GB	-0.1	**2.0**		-0.1		1.8
Total imports	-0.2	2.5	-0.1	-0.3	4.6	
2025						
FR		0.0	0.0		0.1	0.0
BE	0.0		0.0	0.1	**2.4**	2.5
DE	0.0	0.0		0.0		-0.1
NL		-0.1	0.0		-0.1	-0.2
GB	-0.1	**4.2**		0.0		4.0
Total imports	-0.1	4.0	0.0	0.0	2.4	
2030						
FR		0.0	0.0		-0.1	0.0
BE	0.0		0.0	0.0	**2.3**	2.2
DE	-0.1	0.0		-0.1		-0.1
NL		0.0	0.1		-0.2	-0.1
GB	0.1	**5.1**		0.1		5.3
Total imports	0.0	5.2	0.1	0.1	1.9	

3.4 Prices and price changes

38. Figure 14, Figure 15, and Figure 16 illustrate the change in baseload, peak and off peak prices respectively, as a result of the Nemo interconnector. The figures show that in 2020 off-peak Belgian exports to GB push up Belgian off-peak prices, but that this effect is offset in peak hours, when GB exports to Belgium, causing a fall in peak prices and, overall, a drop in Belgian baseload prices. Conversely, both peak and baseload GB prices increase in 2020 as a result of the

Nemo interconnector. Baseload GB prices are not affected, probably because the flows which are moving the prices only appear in peak hours.

39. By 2030, as we mention above, GB has very low off-peak prices, relative to Belgium. Off-peak exports from GB to Belgium therefore push down off-peak Belgian prices. However, the low off-peak prices in GB mean that peak prices have to rise so that generators recover sufficient revenue. As a result, peak GB prices are higher than peak BE prices, and peak power generally flows from Belgium to GB. The net effect is that in 2030 Belgian baseload and peak prices rise. In general, the price effects on the GB market are much smaller than for the Belgian market, because the GB market is much larger and so Nemo flows do not move GB prices as much as in Belgium.

Figure 14: Base case median change in baseload prices as a result of the Nemo interconnector

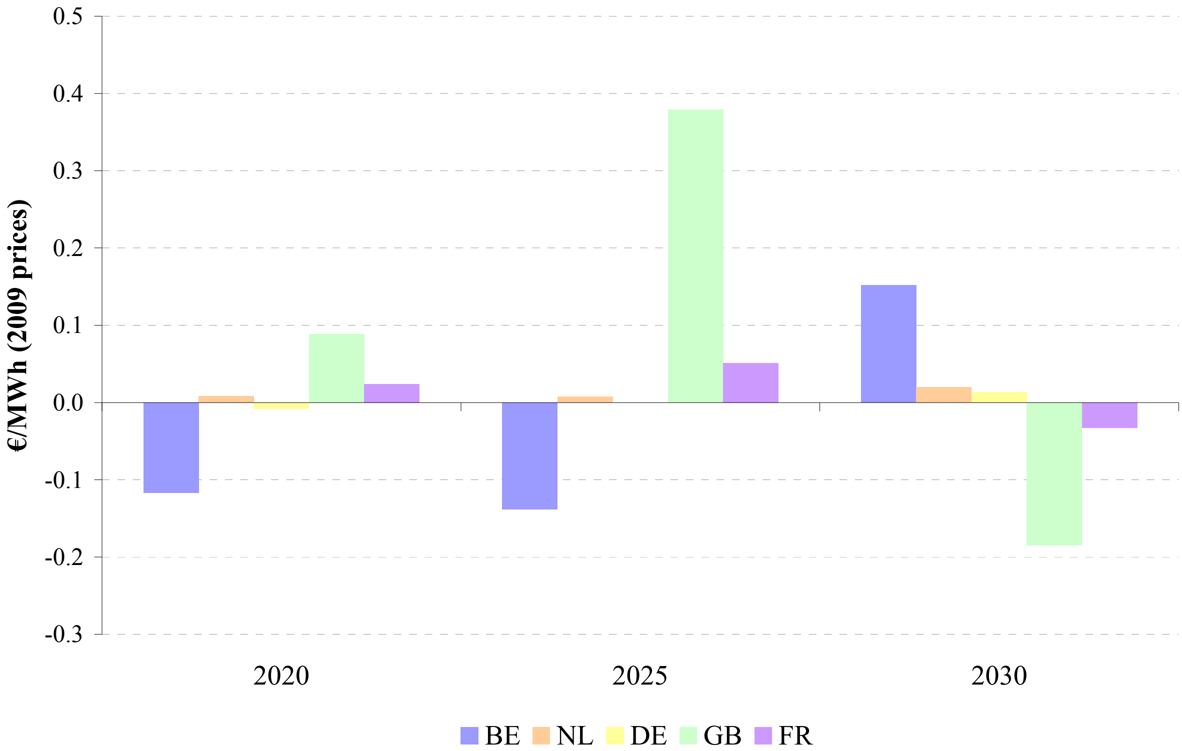


Figure 15: Base case median change in peak prices as a result of the Nemo interconnector

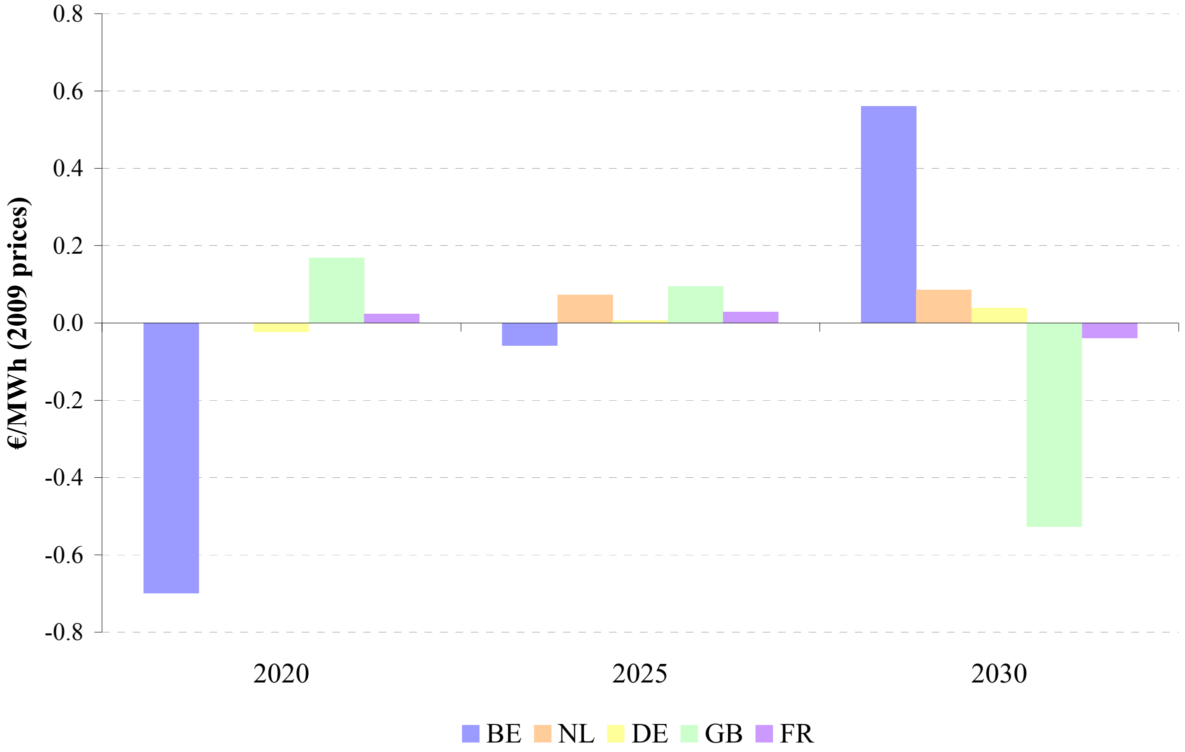


Figure 16: Base case median change in off-peak prices as a result of the Nemo interconnector

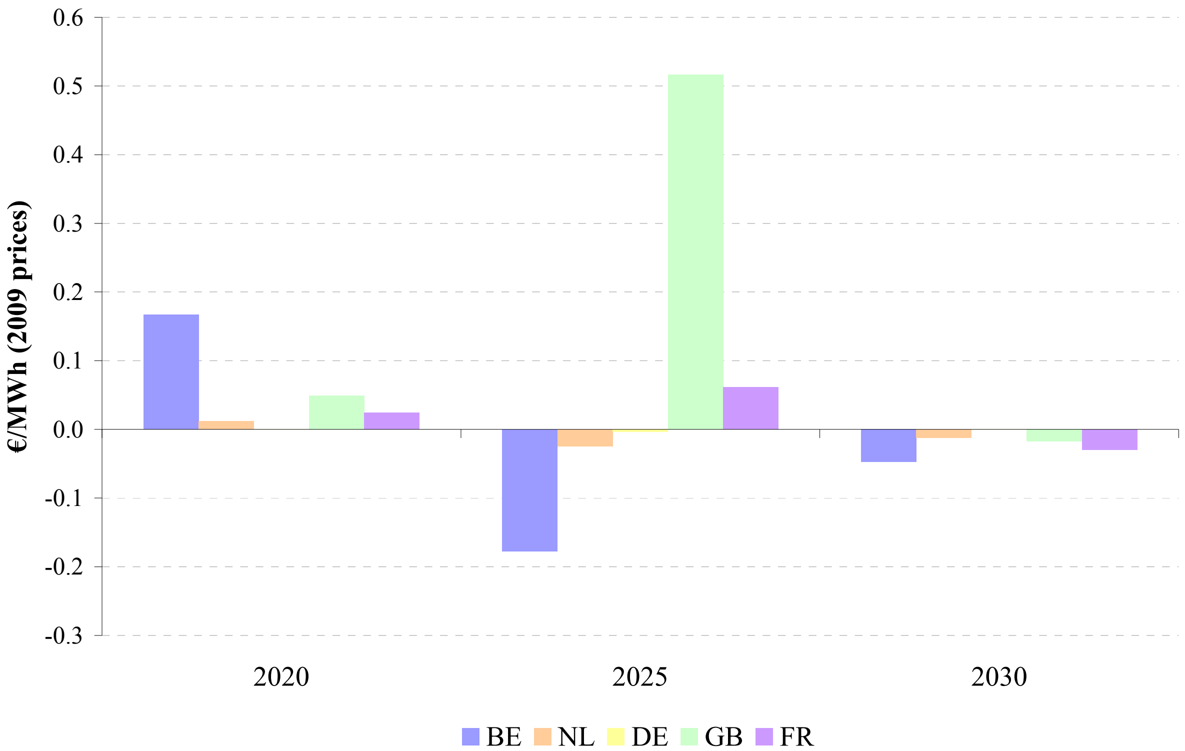


Table 4: ***Base case*** **median baseload prices probabilistic base case, €/MWh (2009 prices)**

	With GB-BE cable			Without GB-BE cable			Difference (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Germany	51.51	54.05	55.76	51.51	54.05	55.75	-0.01	0.00	0.01
Belgium	51.32	54.52	56.01	51.43	54.66	55.86	-0.12	-0.14	0.15
France	49.49	50.68	51.57	49.47	50.63	51.61	0.02	0.05	-0.03
Netherlands	52.16	53.67	54.91	52.16	53.66	54.89	0.01	0.01	0.02
GB	53.72	49.75	48.32	53.64	49.37	48.51	0.09	0.38	-0.18

3.5 Consumer and producer welfare

40. Figure 17 and Figure 18 respectively show the change in producer and consumer welfare as a result of the Nemo interconnector, for the countries modelled. The changes in welfare correspond to changes in price levels due to the Nemo interconnector. As we would expect from the price results, GB producer welfare (profits) increase in 2020 and 2025, since Nemo increases GB baseload prices. In Germany in 2020 baseload and peak prices reductions cause producer welfare to fall slightly.

41. The pattern of changes in consumer welfare is generally the mirror image of the changes in producer welfare, though it is not equal and opposite, particularly for Belgium. In particular, in 2020 both Belgian producers and consumers experience an increase in their welfare. In a 'closed' system without cross-border interconnectors this would not be possible. But with interconnectors that are large relative to domestic demand changes in the same direction are possible. In 2020, Belgian consumer welfare increases because of the fall in baseload prices. While this is to the disadvantage of Belgian producers, the effect is more than offset by the opportunity that Nemo provides to export electricity to GB, especially during off-peak periods. (Overall, generation in BE increases by 2% in 2020 as a result of Nemo.) The volume of Belgian exports to GB is sufficient to increase producer welfare, while at the same time consumer welfare increases. Other countries have a more 'normal' pattern of consumer welfare changes, where the changes in producer welfare mirror the changes in consumer welfare.

42. In 2025 there is a sharp rise in GB producer welfare, which reflects the relatively large effect of Nemo on baseload and peak GB prices in that year due to the tight capacity margin in BE that year. In 2030 GB experiences negative producer welfare, due to the fall in peak prices caused by Belgian imports via Nemo.

43. Figure 19 illustrates that the sum of the changes in producer and consumer welfare for the probabilistic base case. Initially, Belgium makes the biggest net gain from the interconnector project, but then the increases in GB become larger. We think it is not correct however to think of Figure 19 as a trend that will continue, with GB welfare continuing to increase and Belgian welfare falling further. Rather, the period 2020 to 2030 represents a transition to a more sustainable low carbon generating park. This transition is largely complete in 2030, and so the 2030 welfare results are more likely to represent an equilibrium, rather than form part of a continuing trend. The data underlying these figures can be found in Appendix II.1.

Figure 17: ***Base case*** **change in median producer welfare as a result of the Nemo interconnector**

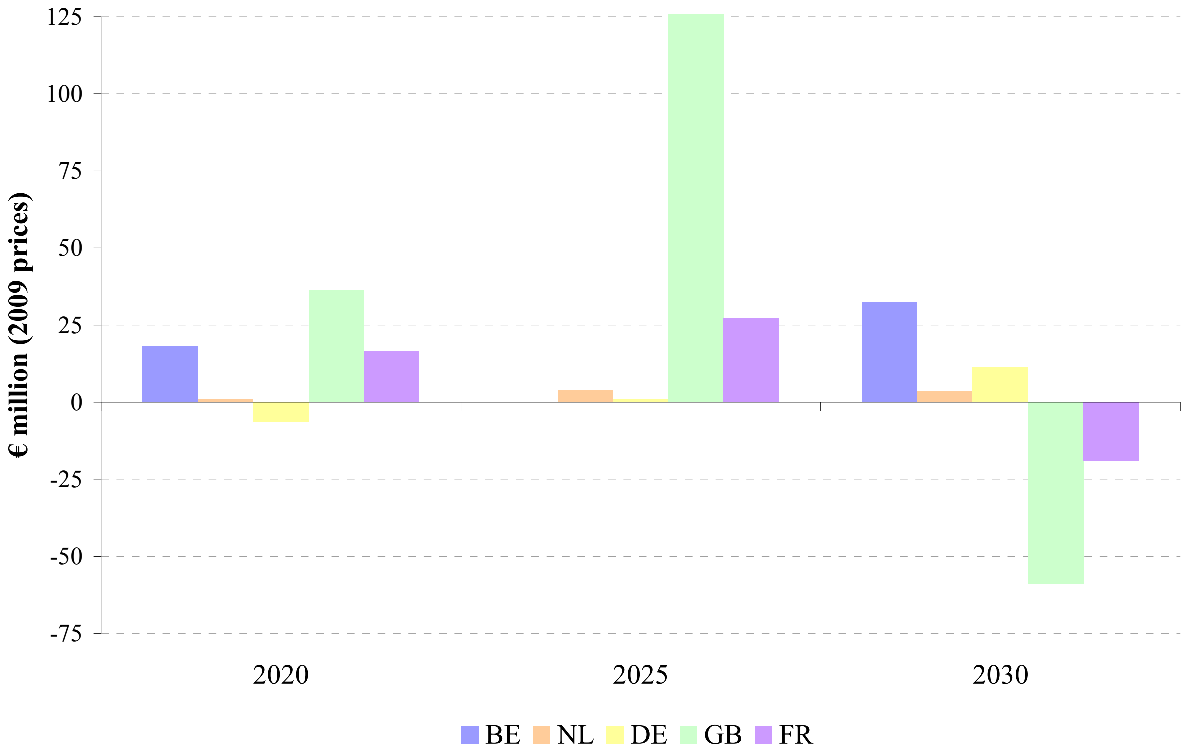


Figure 18: ***Base case*** **median change in consumer welfare as a result of the Nemo interconnector**

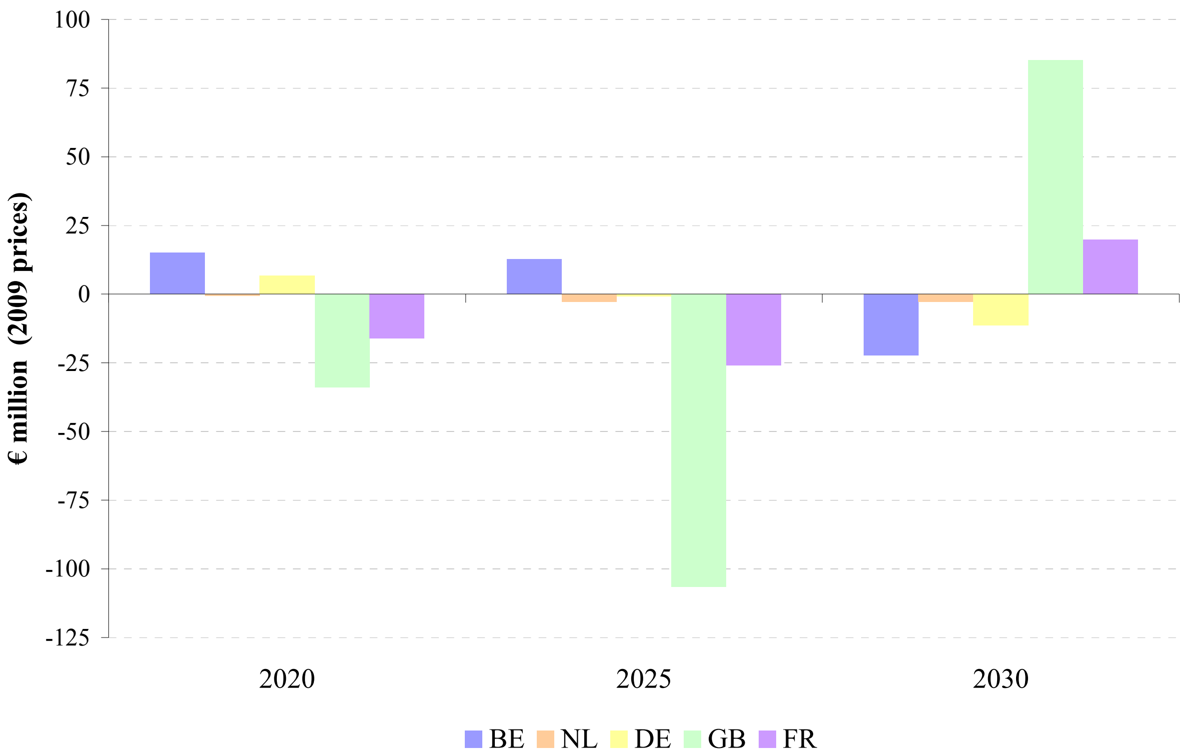


Figure 19: *Base case* median change in overall welfare as a result of the Nemo interconnector

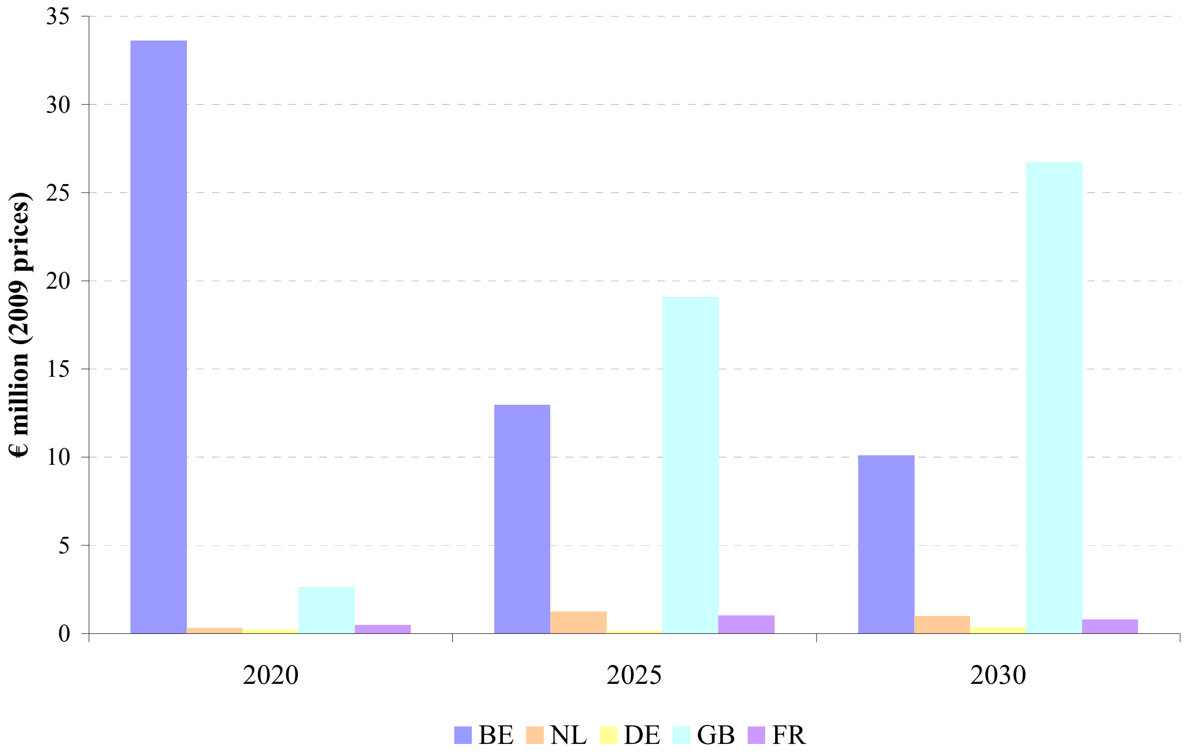


Figure 20: *Base case* distributions of change in overall Belgian welfare (€ million, 2009 prices)

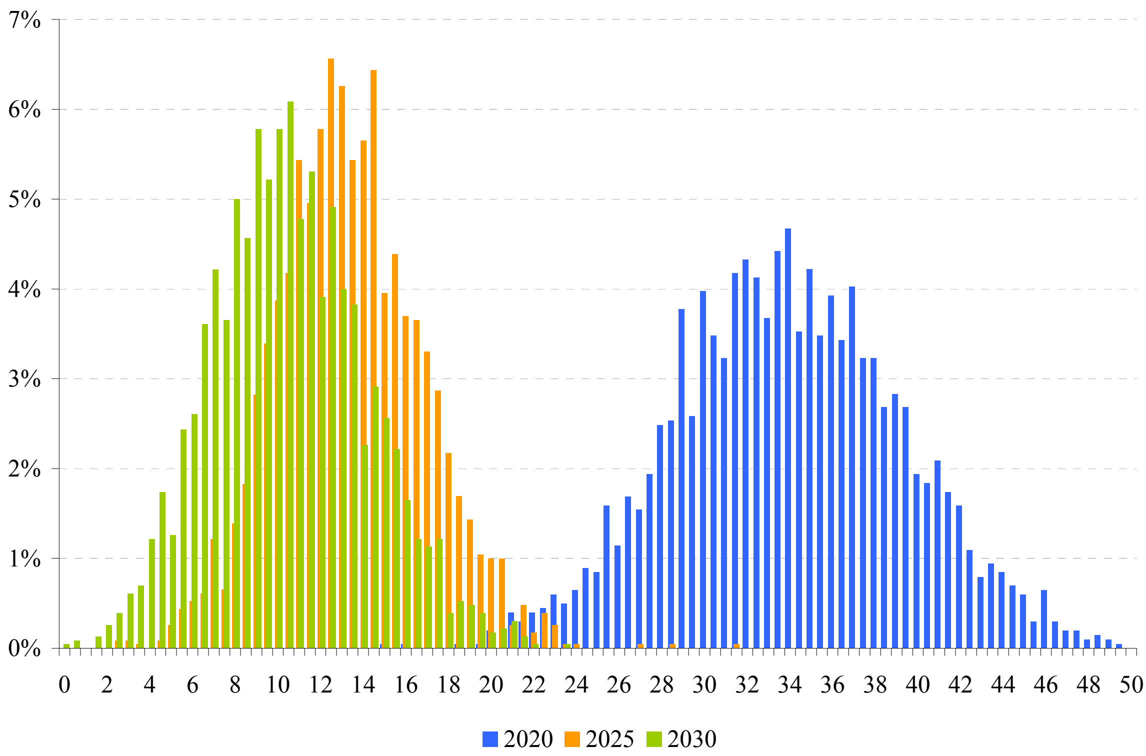
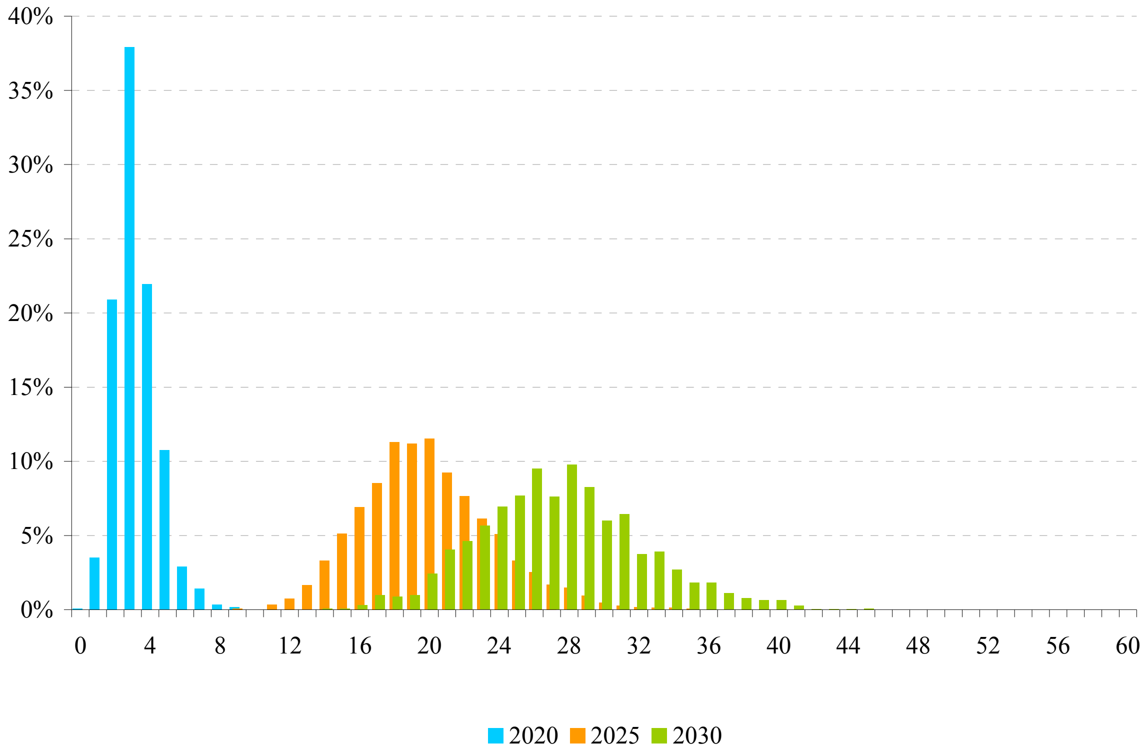


Figure 21: *Base case* distributions of change in overall GB welfare (€ million, 2009 prices)



4 Scenarios and sensitivities

4.1 Description of scenarios and sensitivities

44. We have modeled a number of variations on the base case, as described below:

- **Scenario 1 – equal marginal costs for coal and gas plants**
    - We maintain the same capacities as in the base case, so that the 20% target for renewable energy production is met in all countries.
    - We adjust the base case coal prices upward so that marginal costs of coal and gas fired plants, including ETS (carbon) costs, are very similar. In the base case coal plants are substantially cheaper than gas-fired plants (see Figure 6 on page 8).
- **Scenario 2 – lower wind capacity** but overall capacity margin maintained
    - In this scenario we reduce new wind-capacity additions as follows: 30% less overall in all other countries except that (a) onshore Belgium wind capacity stays the same and (b) in Germany there is 25% less onshore and 50% less offshore;
    - Note that to compensate for the reduction in wind capacity, we add back in the equivalent capacity of thermal plant. For example, 100 MW of offshore wind will be replaced with 35 MW of thermal plant. This means that the overall margins, after de-rating wind capacity, remains the same as in the base case. We add a mix of thermal plants designed to keep the overall plant mix the same as in the base case. Consequently the 20/20/20 targets are not met in this scenario.
- **Scenario 3 – combination of scenarios 1 and 2**:
    - We have made the same adjustments in coal prices as in scenario 1 and the same adjustments in capacities as in scenario 2;
- **Scenario 4 –Nuclear lifetime extension**. In this scenario we have extended the life of all the nuclear plants in Belgian from 40 years to 50 years. We also assume a more ambitious nuclear build program for GB, with an additional 5.3 GW of nuclear power installed by 2020 relative to the base case. In this scenario we 'swap' gas fired plants for nuclear plants, so that the total capacity of gas-fired plant and nuclear plant is the same in this scenario and the base case.

In addition to the scenarios described above, which focus on general adjustments to the base scenario, we have also carried out a number of sensitivity tests looking at the impact of specific assumptions.[10] At least in some cases, it would not be reasonable to assume that the sensitivity adjustment would apply in all three years we model.

[10] Note that the sensitivities are numbered from a previous project. In the current project we did not need to run sensitivity2, which is why it is missing.

- **Sensitivity 1 – increased onshore wind in BE**, with reduced biomass capacity. We increase onshore wind by 3,340 MW in 2020 relative to the base case, but reduce the biomass capacity so that energy production is about the same as in the base case. The reduction in biomass is made once only in 2020. We then add the same amount of onshore wind each year to reach an installed capacity of onshore wind in 2030 in Belgium of 6200 MW, about 4,100 MW more than in the base case.
- **Sensitivity 2 – reduced interconnector capacities**. To account for the possibility of 'loop flows', we reduce the interconnector capacity in the following directions:
  - NL to BE: 400 MW
  - DE to BE: 300 MW
  - DE to FR: 300 MW
  - DE to NL: 300 MW
  - BE to FR: 400 MW
  - Note that we increase the interconnector capacity in the opposite directions by the same amount, so that the interconnector capacity is really swapped from one direction to another.
- **Sensitivity 3 – a cold winter case**. We used historical Heating Degree Days data (HDD) and estimated a relationship between the HDD in a month and electricity demand. We estimated separate HDD/demand relationships for Belgium, France and Germany, the countries whose electricity demand is most sensitive to temperature. Using these relationships, we estimated demand in the winter months assuming the HDD were 10% higher than the highest HDD recorded in the last 10 years. We then estimated the percentage difference between this demand and the demand we would forecast given the actual HDD observed. We increased base case demand by this amount to simulate severe winter demand. Table 5 summarizes the increases in demand by country for each winter month. Appendix VII gives details of the HDD/demand relationships.

Table 5: Increase in demand by country and month in the severe winter scenario

	France	Belgium	Germany
January	12.52%	8.1%	9.1%
February	5.41%	3.8%	5.0%
November	4.62%	2.0%	3.6%
December	0.85%	1.2%	2.4%

4.2 Scenario and sensitivity results

4.2.1. Congestion rents

45. Figure 23 illustrates the congestion rents on the Nemo interconnector under the various scenarios and sensitivities and Figure 23 shows how these rents compare to the base case. Similarly, Figure 24 shows the change in the TSO revenues for BE and GB as a result of Nemo across the scenarios and sensitivities whilst Figure 25 compares these revenues to the base case. Details of the results for individual scenarios/sensitivities can be found in Appendix II.

46. Scenarios 2 and 3 consistently have the lowest rents, because they are the scenarios with the lowest amounts of wind. As we noted earlier, intermittent wind creates a lot of price volatility, and because hourly wind-power production is not fully correlated between GB and Belgium this creates price differences between the two markets which generate congestion rents. Therefore lower wind lowers congestion rents. This also means that the overall TSO revenues are generally lowest under these scenarios. For this same reason, sensitivity 1 – which involves an increase in installed wind capacity in Belgium – has consistently the highest congestion rents (and generally the highest TSO revenues) of all the scenarios and sensitivities.

47. Scenario 1 – which has higher coal prices than the base case – reduces congestion rents compared to the base case. This is because higher coal prices increase GB off-peak prices. Since in the base case Belgium has higher off-peak prices, scenario 1 reduces the price difference between Belgium and GB and reduces congestion rents. The reduction in overall TSO revenues is similar, because the change in coal prices has little overall impact on the rents on other borders (some go up and others go down). Combining scenarios 1 and 2 in scenario 3 generally leads to lower rents then either of the individual scenarios.

48. Sensitivity 2 – which reduces the interconnector capacity from NL and DE to BE but increases it from FR to BE (and does the opposite for flows in the reverse direction) – produces congestion rents and TSO revenues that are very similar to the base case, except in the case of BE in 2020, for which there is a large increase in TSO revenues. In this year, the plant portfolios across Europe vary more than they do in later years and the increased capacity for imports to BE from FR under this scenario enables BE to export more power to GB with Nemo and this increases the BE TSO revenues.

49. Finally, sensitivity 3 – the high winter demand case – has very little impact on Nemo congestion rents or the TSO revenues.

Figure 22: Median Nemo congestion rents across scenarios/sensitivities

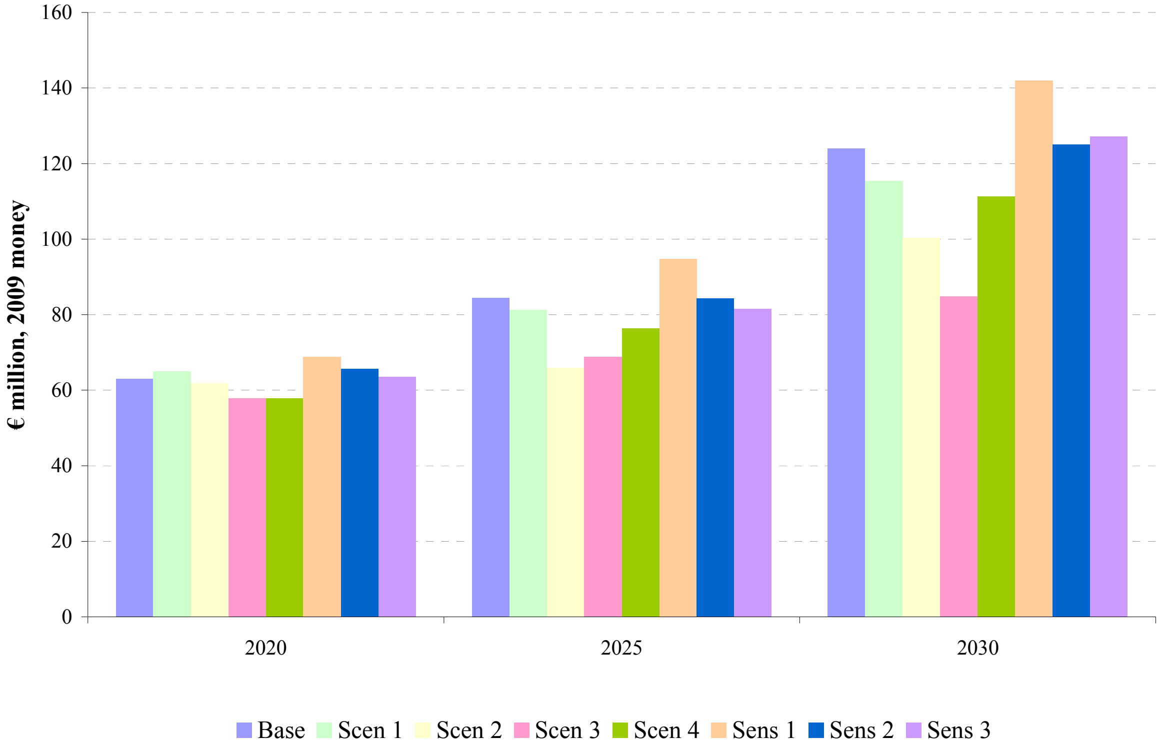


Figure 23: Change in median congestion rents from the base case

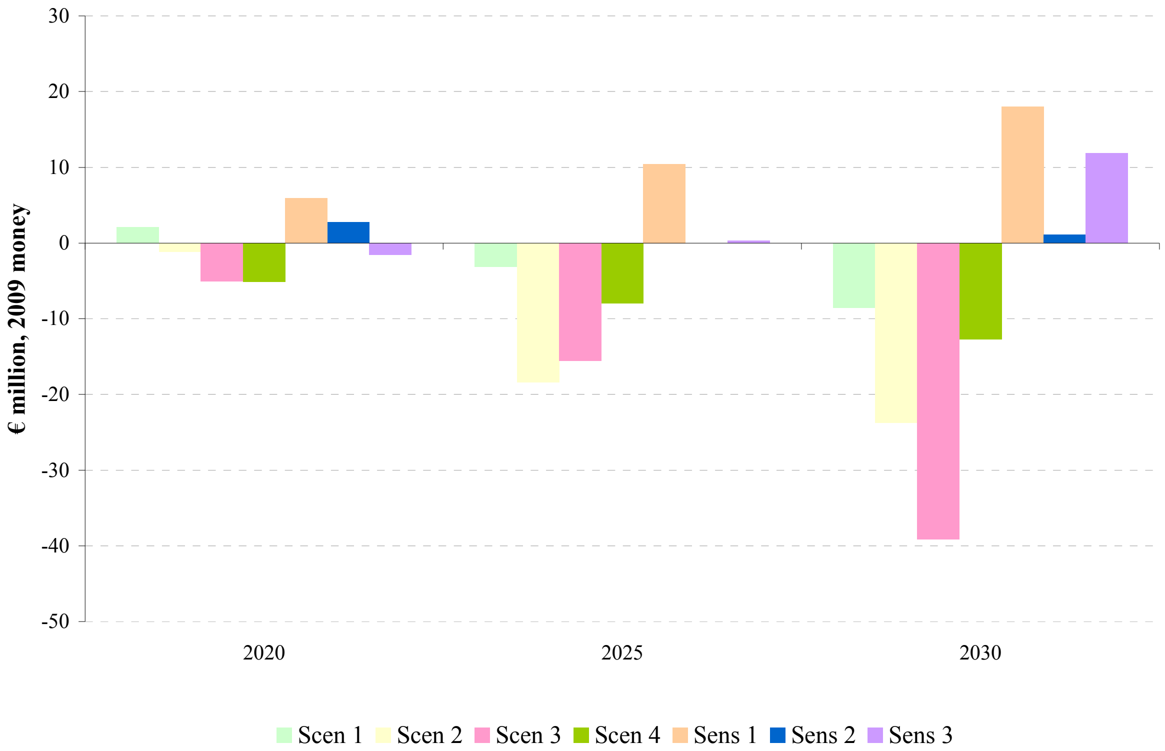


Figure 24: Median TSO revenues for BE and GB across scenarios/sensitivities

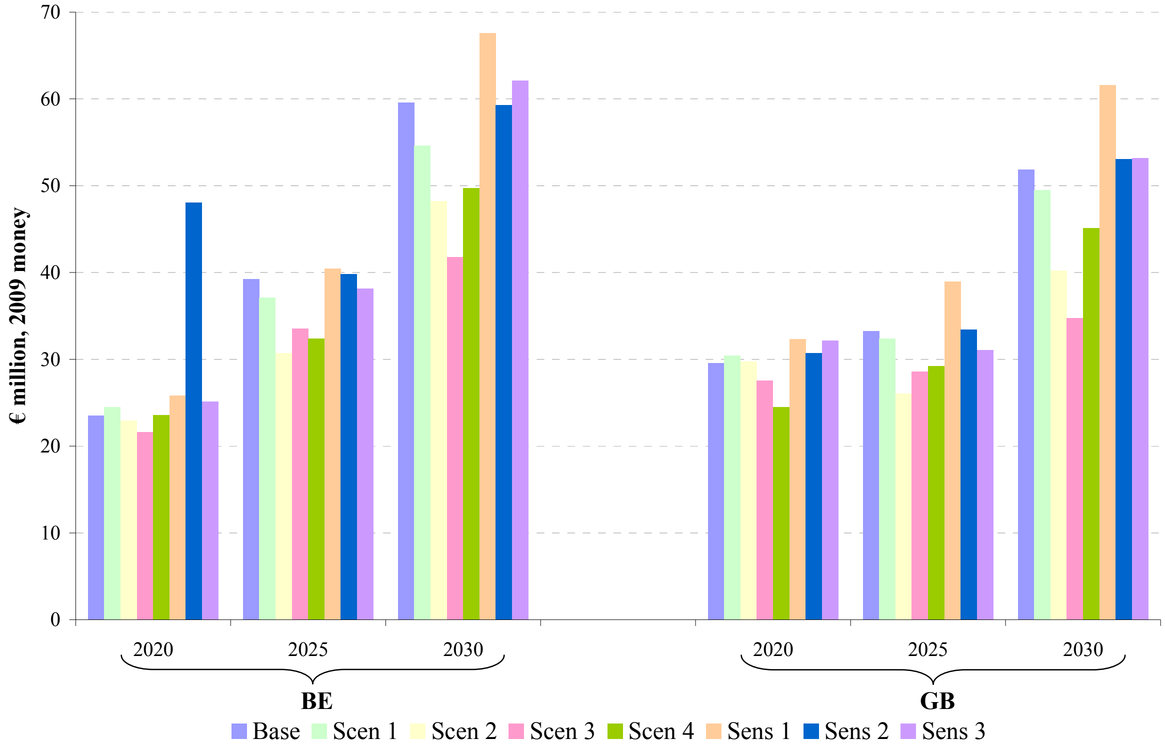
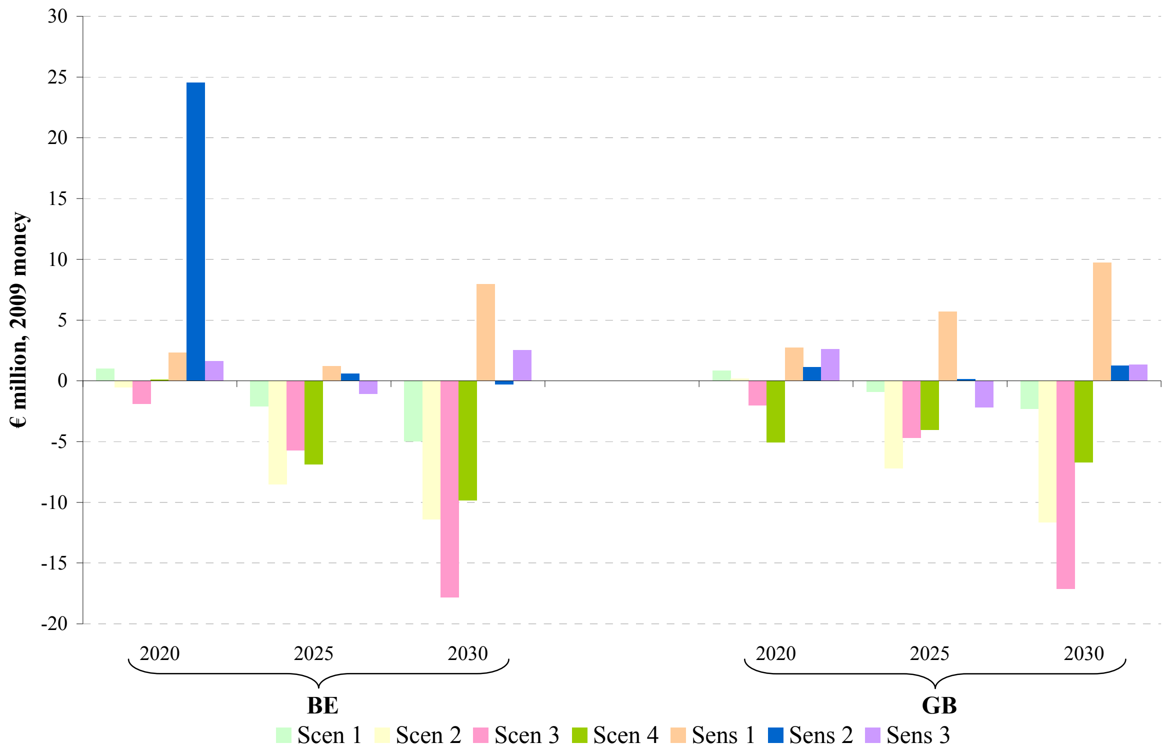


Figure 25: Change in median TSO revenues for BE and GB from base case



4.2.2. Welfare

50. Figure 26 illustrates the impact on overall welfare in BE and GB of the Nemo interconnector under the various scenarios and sensitivities whilst Figure 26 shows how these changes in welfare compare to the base case. Again, details of the results for individual scenarios/sensitivities can be found in Appendix II.

51. Under scenario 1, the high coal price case, there is little change in BE overall welfare from the base case but the increase in overall welfare is lower in GB in 2025 and 2030. The higher coal prices reduce the exports from GB and the resulting reduction in consumer welfare (due to higher prices) outstrips the increase in producer welfare because GB demand is so much larger than the available interconnector capacity.

52. The low wind scenarios – scenarios 2 and 3 – lead to lower increases in overall welfare for both BE and GB. In BE, the lower wind reduces the net imports but these decrease consumer welfare more than producer welfare increases. Conversely, in GB, lower wind leads to fewer off-peak exports but more peak exports and peak prices increase more than off-peak prices fall so that change in consumer welfare falls more than the change in producer welfare. Under the higher on-shore wind case (sensitivity 1), the major impact is in 2025 when the change in BE overall welfare increases significantly due to the impact that zero priced power has in a tight capacity situation.

53. Scenario 4 – the nuclear prolongation case leads to an increase in the change in BE overall welfare in 2025 and 2030 and a decrease in 2020. The decrease in 2020 is caused by the assumption that there is more nuclear capacity in GB (for the other years, the GB nuclear capacity is the same as in the base case) which gives rise to additional GB exports without a material change in prices. Consequently, the change in BE consumer welfare remains relatively constant but there is a drop in the change in BE producer welfare.

54. Sensitivity 2 (the "swapped" interconnector capacity") leads to higher exports from BE because import capacity is reduced and export capacity is increased. This increases prices and, once again, the adverse impact of this on the change in consumer welfare outweighs the positive impact on change in producer welfare. By 2030, however, the change in plant portfolios means that there is very little change in overall BE net exports but the split of peak and off-peak flows means that change in producer welfare increases more than change in consumer welfare decreases. Unsurprisingly, there is relatively little impact on the change in GB overall welfare since there are no changes to the GB interconnectors.

55. Similarly, the cold winter sensitivity in BE, DE and FR has relatively little impact on GB overall welfare except in 2025, where higher winter demand exacerbates the BE capacity squeeze and reduces further BE peak exports to GB, leading to a higher change in producer welfare than in consumer welfare. For BE, the change in overall welfare is lower in all three years because Nemo reduces the impact that the increased demand has on prices and so consumer welfare increases more as a result of the cable than producer welfare falls.

Figure 26: Median change in overall welfare for BE and GB across scenarios/sensitivities

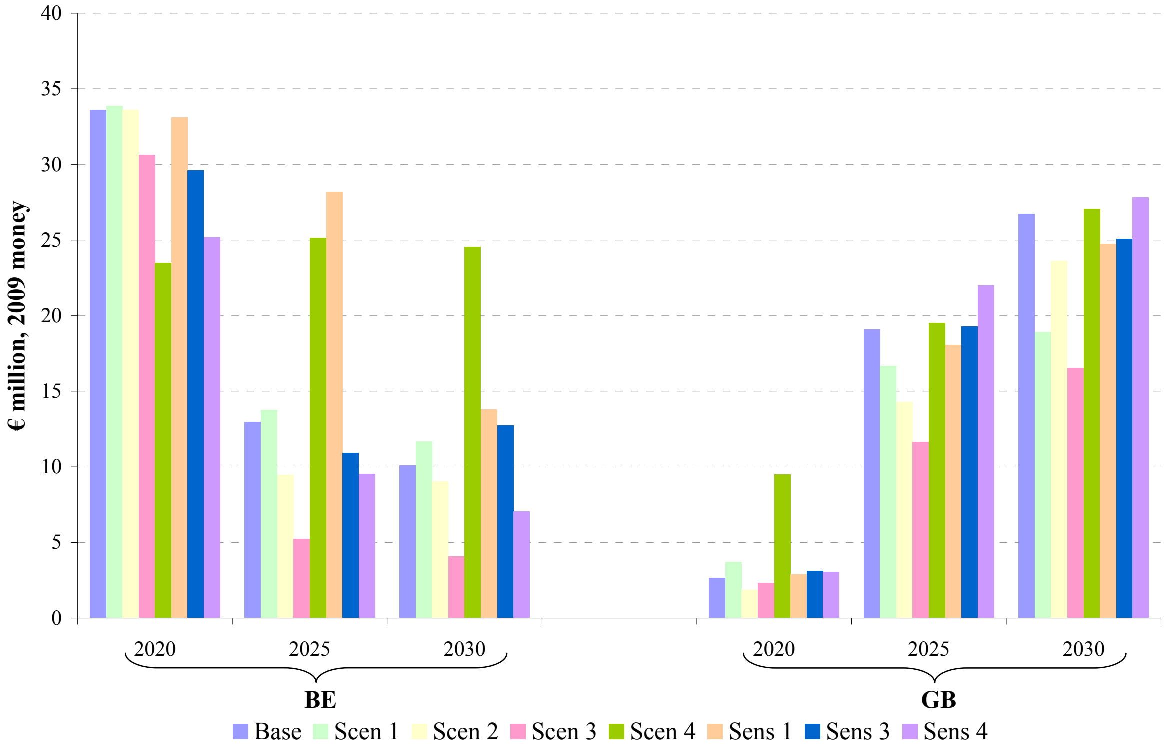
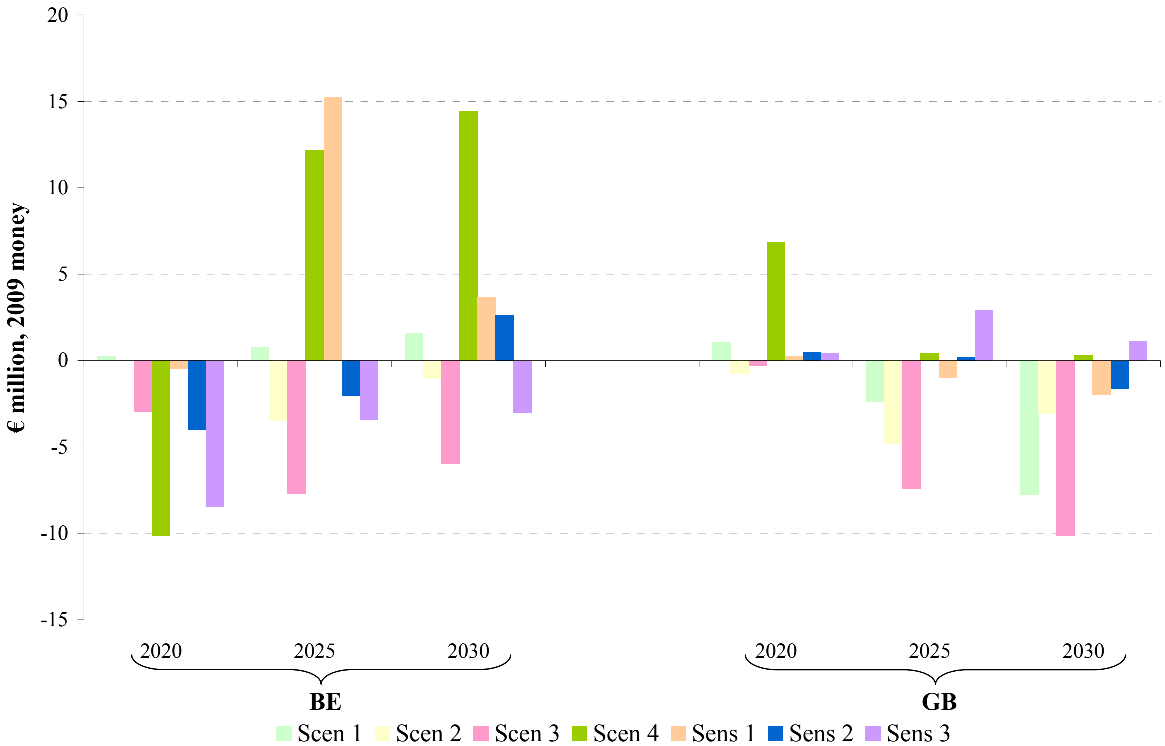


Figure 27: Change in median overall welfare for BE and GB from base case



56. Need some discussion

4.3 Recent GB electricity market proposals

57. In December 2010, the UK Government put out for consultation a series of major changes in the design of the GB electricity market.[11] Because of the timing of the consultation release, we were not able to incorporate a scenario which modelled the proposals. However, in this section we discuss in qualitative terms what the impact of the proposals might be.

58. Three of the proposals are particularly relevant to this analysis. These are proposals to:

- Introduce a carbon price floor, so in other words a minimum price for carbon for GB generators. The level of the floor is not specified, but the accompanying modelling assumes a price of £70/tCO2 by 2030 – significantly above the carbon prices we use.
- Feed-in tariffs for nuclear, CCS and renewables.
- Long term reserve contracts (a capacity-type payment) for new plants (mostly peaking plants) required to maintain adequate security of supply.

59. We briefly discuss the effect of each measure below.

4.3.1. Carbon price floor

60. A carbon price floor will only have an effect on GB electricity prices when fossil-fuelled plants set the price and pass through the cost of carbon in their offers. Since our model shows that renewables will in future frequently set off-peak prices, the effect of the carbon price floor will primarily be an increase in peak GB prices. Except in 2025, GB and Belgian peak prices are relatively close with the Nemo interconnector (the median difference is within 0.5 €/MWh), so a carbon floor is likely to increase flows from Belgium to GB.

61. Of course, the effect depends on the level of the price floor relative to the EU ETS carbon price. Since the UK Government has not specified the price floor, it is hard to be certain as to the impact of this proposal on Nemo. For example, by 2020 and beyond, it is possible that the ETS carbon price will have risen sufficiently for the carbon price floor to have little impact.

4.3.2. Feed-in tariffs

62. One of the proposals is that low-carbon generation, including nuclear plants and coal plants with carbon capture and storage, would benefit from a feed-in tariff (FIT) that would be higher than expected market prices. The FIT would actually be implemented as a contract for difference. As a result, low-carbon generation would offer power into the market at a very low price, since they are compensated via the FIT and so have an incentive to run, even when market prices are very low.

63. For renewables this provides similar incentives as the existing green certificate scheme. In our model we already assume that renewables and nuclear have low or zero marginal costs. Hence, the inclusion of a FIT would not make little difference to our model and the results. However, the

[11] Department of Energy and Climate Change, Electricity Market Reform Consultation Document, December 2010. Available at www.decc.gov.uk.

FIT regime may make it more likely that high levels of wind penetration and nuclear new build included in scenarios are achieved.

4.3.3. Capacity contracts

64. To the extent that capacity or reserve contracts remove the need for new peak plants to recover their capital costs from the power (energy) market, reserve contracts will reduce peak prices in GB. Given the depressing effect of FITs and reserve contracts on prices, it seems unlikely that conventional plant reserve contracts or FITs are likely to be built. Reserve contracts could depress peak GB prices, relative to the results in our model, and result in more peak exports from GB to Belgium, where peak prices might be higher. However, we note that the carbon price floor will tend to push peak prices up, in contrast to the effect of reserve prices. It is not clear which effect would dominate.

65. Also of interest for Nemo is that interconnector users could be eligible for capacity contracts. However, it seems that this would only be possible for capacity that is allocated to users explicitly over the medium to long term (1 year +). Otherwise there would be no guarantee that reserve will be available via interconnector.

4.3.4. Conclusions

66. We consider that the carbon floor proposal and the reserve contract proposals are likely to counteract each other: the carbon floor proposal could push peak prices up whilst reserve contracts could reduce them. It is difficult at this stage to predict what the overall effect will be but it is likely that any impact would be greater for flows than for congestion rents. In other words, even if the direction of net flows changed this would not necessarily result in reduced congestion rents, since these depend only on the absolute difference in prices.

5 Competition analysis

5.1 Methodology

67. We assess the competitive effects of the Nemo cable in 2020 by reference to four measures of concentration: the concentration ratio (CR), the Herfindahl-Hirschman Index (HHI), the Pivotal Supplier Index (PSI) and the Residual Supplier Index (RSI). For each index, we perform calculations including and excluding the Nemo cable and hence measure its impact:

- The CR(m) is the percentage of market share held by the largest m firms in an industry. For the Belgium and UK markets we calculate the CR(1) and CR(3), that is, the total market share of the largest generator and the largest 3 generators in each market, respectively.
- The HHI is the sum of the square of the market shares of the firms in a particular market. The index ranges from 10,000, which represents a complete monopoly, to an HHI of zero, which represents a 'perfectly competitive' market made up of many thousands of small market actors. An HHI of 1,800 or higher is generally accepted as a benchmark in competition policy for cases to raise a market power issue.[12] Conversely, a market with an HHI value of 1,000 or lower is generally accepted as an un-concentrated market by competition policy practitioners.[13]
- The PSI is calculated using a binary variable (0 or 1) that examines whether or not a given generator (generally the largest generator) is necessary (or 'pivotal') to ensure that demand is met. If in a given period, demand in a specific market cannot be met without at least some power from a supplier, that supplier is pivotal and may be supposed to have market power during that period.[14]
- The RSI is a generalized continuous variation of the PSI. It reflects the proportion of the demand in the relevant market that smaller (or 'residual') suppliers would be able to meet, were the largest player to withdraw its capacity. Generally, the RSI is calculated as the ratio of residual supply (total supply, including import capacity, minus the largest seller's supply) to the total demand. The RSI determines not only whether a firm is pivotal or not but it also helps to assess the degree to which a market has to rely on the largest firm's available capacity to meet demand. When the RSI is less than 100 percent, the largest firm becomes pivotal and its generation is needed to meet the total demand. Conversely, when the RSI is larger than 100 the largest firm is not pivotal and hence has less influence over the price in the market.

---

[12] To be indicative of a HHI equal to 1,800, this means the presence of five to six companies with an identical market share. If there were five (six) identical players in the market, the HHI would be 2,000 (1,667).

[13] For indicative purposes, a market with ten identical companies with a market share of 10% each will have a HHI of 1,000.

[14] For example, generator A would be pivotal in a given hour if demand was 40 GW, and the supply from all other generation firms *except* firm A is 28 GW. In this case, some output (12 GW) would be required from generator A, and hence generator A has the ability to exercise market power.

68. The HHI and concentration ratios (CR(m)) are common benchmarks (based on market shares) used by competition policy practitioners (including the European Commission) to assess the level of competition in all type of markets.[15] The PSI and the RSI are more specific benchmarks commonly used to evaluate the level of competition in electricity markets. RSI and PSI measures are extensively used in the US (but are less commonly used by European regulatory and competition authorities).[16]

69. For the computation of the four measures of concentration we use two ‘extreme’ allocation scenarios:

- *Atomistic competition*: The capacity of the Nemo cable is allocated to 10 new independent companies entering the market. This scenario will result in the greatest increase in competition.
- *Largest company allocation*: The import capacity of the Nemo project is apportioned entirely to the largest firm in the market. This scenario represents the largest reduction in the level of competition in a market that could result from the Nemo cable, and helps us to define potential mitigation measures.

70. Competition policy authorities (including the European Commission), energy regulators (including the European Association of Energy Regulators, ERGEG) and market participants (including the European Network of Transmission System Operators, ETSO) take the view that implicit auctions are preferable to explicit auctions as a means of efficiently allocating cross border capacity whilst promoting competition.[17] To some extent, the atomistic competition scenario can be thought as a benchmark for a situation in which the Nemo interconnection capacity is assigned through implicit auctions, since under an implicit auction no party actively controls interconnector capacity. Flows are simply determined by the result of bids and offers in the market. Conversely, the largest company allocation scenario can be considered as akin to a situation in which the Nemo interconnection capacity is allocated through an explicit auction

---

[15] The HHI is the measure of market concentration that is most commonly used by competition authorities the world over. For example the HHI is used extensively in the European Commission’s horizontal merger guidelines (Guidelines on the assessment of horizontal mergers under the Council Regulation on the control of concentrations between undertakings (2004/C 31/03). The US Department of Justice also uses the HHI in its merger guidelines (see U.S. Department of Justice and Federal Trade Commission, Horizontal Merger Guidelines, issued April 2, 1992, revised April 8, 1997 (DOJ/FTC Merger Guidelines).

[16] The PSI analysis is a standard feature of proceedings to allow so-called Market Based Rates (which are rates for selling power that are not approved by a regulator) in the US (Order on Rehearing and Modifying Interim Generation Market Power Analysis and Mitigation Policy, 107 F.E.R.C. § 61,018 (2004)). The independent system operators CAISO and ERCOT in the US use the PSI analysis to determine if transmission constraints should be deemed competitive. The RSI was devised by the California Independent System Operator (CAISO) (see Sheffrin, A. “Predicting Market Power Using the Residual Supply Index” Mimeo, Department of Market Analysis, California ISO, 2002).

[17] See for instance, European Commission Report, *DG for Competition Energy Sector Inquiry*, January 2007; European Commission Report, *DG Energy and Transport, Report on Regulation 1228/2003 on Cross Border Trade in Electricity*, May 2007; ERGEG Report, Coherence and Convergence Report, July 2007; and ETSO Interim Report, *Development and Implementation of a Coordinated Model for Regional and Inter-Regional Congestion Management*, April 2008.

mechanism and these results in the entire Nemo transmission capacity being captured by the largest firm in each market. In practice, of course, at any one time the capacity could only be assigned to the largest firm in one or other market.

71. One complicating factor in assessing the competitive effect of the Nemo cable is how to allocate the new capacity that we assume will have come on-line by 2020. Except for plants that are already under construction, there is inevitably uncertainty about which proposed plants will actually be built and hence there is a significant volume of "undefined new capacity additions", particularly in respect of additions of renewable plants.[18]

72. For the largest company allocation scenario, we allocate all the undefined new capacity additions to the largest existing generators (Electrabel in Belgium and RWE in GB). This is consistent with trying to understand the most adverse impact that the Nemo cable could have. Conversely, for the atomistic competition scenario, we allocate the sum of the undefined new capacity additions to 10 new independent firms. Again, this is consistent with the intention of the scenario, namely to estimate the greatest possible benefit to competition from the Nemo cable.

73. We evaluate the competitiveness effect of the Nemo cable separately in BE and GB. The supply side of the BE market is defined as the total generation capacity in Belgium (23,392 MW in 2020) plus the import capacity of the interconnectors to France (3,652 MW), the Netherlands (1,332 MW) and Germany (1,000 MW). The supply side of the GB market is defined as the total generation capacity in GB (90,449 MW in 2020) plus the import capacity of the interconnectors to France (3,000 MW), Nordpool (1,500 MW) and the Netherlands (1,000 MW).[19] In making our calculations we "derate" the capacity of wind, solar and hydro plants to account for the fact that their typical maximum output is significantly lower than their nameplate capacities. We also take into account the impact of losses on the DC interconnection transmission capacities.

74. The way we include transmission capacity into the concentration measures assume that electricity flows from the neighbouring countries into the BE and GB markets respectively. This is the relevant case to look at, since we are interested in the ability of Nemo to constrain market power. In the event that a party in either GB or Belgium tried to exercise market power, power prices would rise and Nemo would import power in response.

5.2 Effect on competition in the Belgian electricity market

75. Table 6 illustrates the standard measures of concentration for the BE market before and after the completion of the Nemo project. In 2020, Electrabel will still be the dominant firm in the BE market with a market share of at least 42%. Accordingly, the concentration measures for the BE market are high.

---

[18] In addition to new capacity additions that are already under construction or under development we are assuming that a total of 2,450 MW of undefined new capacity additions will come online in Belgium by 2020. We are further assuming that a total of 12,748 MW of undefined new capacity additions will come online in GB by the same time frame period.

[19] The import capacity from Ireland to GB has been netted off demand and so is not listed here.

76. Under the largest company allocation scenario, we allocate 2,876 MW of undefined new capacity to Electrabel. The result is that Electrabel controls around 56% of the total available capacity in BE, and the HHI value (3221 without Nemo) is well above the 1,800 HHI threshold that the antitrust authorities tend to use to define "highly concentrated markets". Moreover, as is only to be expected, the Nemo cable increases the HHI by around 5.5%. Under the atomistic competition scenario, the HHI is lower (2,093 without Nemo) and the Nemo cable might be able to reduce the HHI value by around 151 points (or about 7%).

77. The PSI and the RSI measures further indicate that both with and without the Nemo cable, Electrabel, and only Electrabel,[20] is able to influence prices. However, the extent to which Electrabel is pivotal varies significantly between our two scenarios. Under the largest company allocation scenario where Electrabel is pivotal in about 48% of hours both with and without the cable[21] whilst under the atomistic competition scenario, Electrabel is only pivotal in around 4% of hours even without the cable. Under this scenario, the cable has a positive effect on competition in the sense that it reduces to less than 1% the percentage of the time that Electrabel is pivotal.

Table 6: The effect of Nemo additional transmission capacity on the concentration measures in BE

	Largest Company Allocation		**Atomistic Competition**	
	Before Nemo	**After Nemo**	**Before Nemo**	**After Nemo**
Concentration Ratios				
CR (1)	56%	57%	44%	43%
CR (3)	67%	68%	55%	53%
HHI Test				
HHI Value	3,221	3,398	2,093	1,943
ΔHHI		177		-151
Pivotal Supplier Test (% Hours Pivotal)				
Electrabel	48%	48%	4%	0%
Residual Supplier Test				
Average	103%	103%	120%	128%
Maximum	140%	140%	163%	175%
Minimum	77%	77%	88%	94%

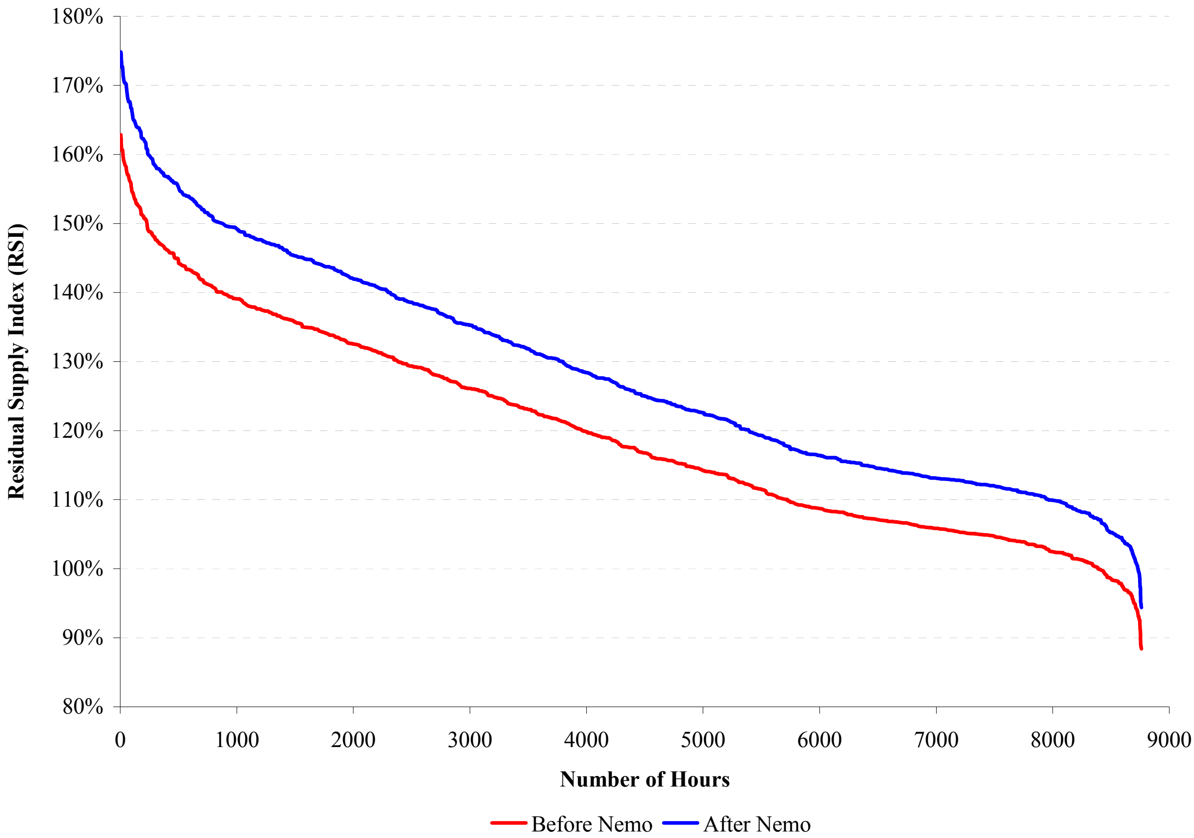
78. Figure 28 below illustrates the effect of the Nemo cable on the RSI values under the atomistic competition scenario. For each RSI value "x", the curve shows the number of hours in the year for which the RSI values are higher than "x". It demonstrates that the pivotal position of Electrabel is weakened with the addition of the new transmission capacity into the BE market. For instance, the Nemo cable will increase by about 4% the number of hours in which the RSI is higher than 100% (from 8,390 hours to 8,728 hours). By reducing the percentage of hours in which Electrabel is

[20] In other words, Electrabel is the only pivotal supplier.

[21] In this scenario we assume that all the Nemo capacity is used by Electrabel. As a result, the residual supply (internal generation owned by other market players plus import capacity into the BE market from France, Netherlands and Germany) remains unaltered before and after the completion of the Nemo project. Since the residual demand remains unchanged, the Nemo project has no effect on the ratio residual supply to total demand.

pivotal, the Nemo project will enhance the level of competition in the market if its capacity is allocated to smaller players or is subject to implicit coupling.

Figure 28: The effect of Nemo on the 2020 RSI in BE under the *atomistic competition* scenario



79. Under the largest company allocation scenario, it is possible to ensure that the competitive situation (as measured by the HHI) remains unchanged, by restricting the proportion of the Nemo capacity that Electrabel can control. We estimate that it would be enough to limit to ensure that no company can control more than 58% of the Nemo import capacity to ensure that the "after Nemo" HHI value remains identical to the "before Nemo" HHI. This calculation represents the maximum mitigation measure that could be required, since the largest company allocation scenario is likely to over-estimate the proportion of new capacity that is built by Electrabel.

5.3 Effect on competition in the GB electricity market

80. Table 7 illustrates the standard measures of concentration for the GB market before and after the completion of the Nemo cable. Unlike the BE market, the GB market is only moderately concentrated, even when the 16,960 MW of available undefined capacity is allocated to RWE. The largest firm in the market, RWE, accounts for only around 34% of the total supply capacity (including imports) and the HHI values range from less than 1,492 in the largest company allocation scenario to only 515 in the atomistic competition scenario. The low level of concentration and the relatively large size of the market (above 90,500 MW of available generation capacity, including imports) when compared with the size of the Nemo cable (1,000

MW ignoring losses) means that the effect of the cable on the GB market is significantly smaller than in the BE market.

Table 7: The effect of Nemo additional transmission capacity on the concentration measures in GB

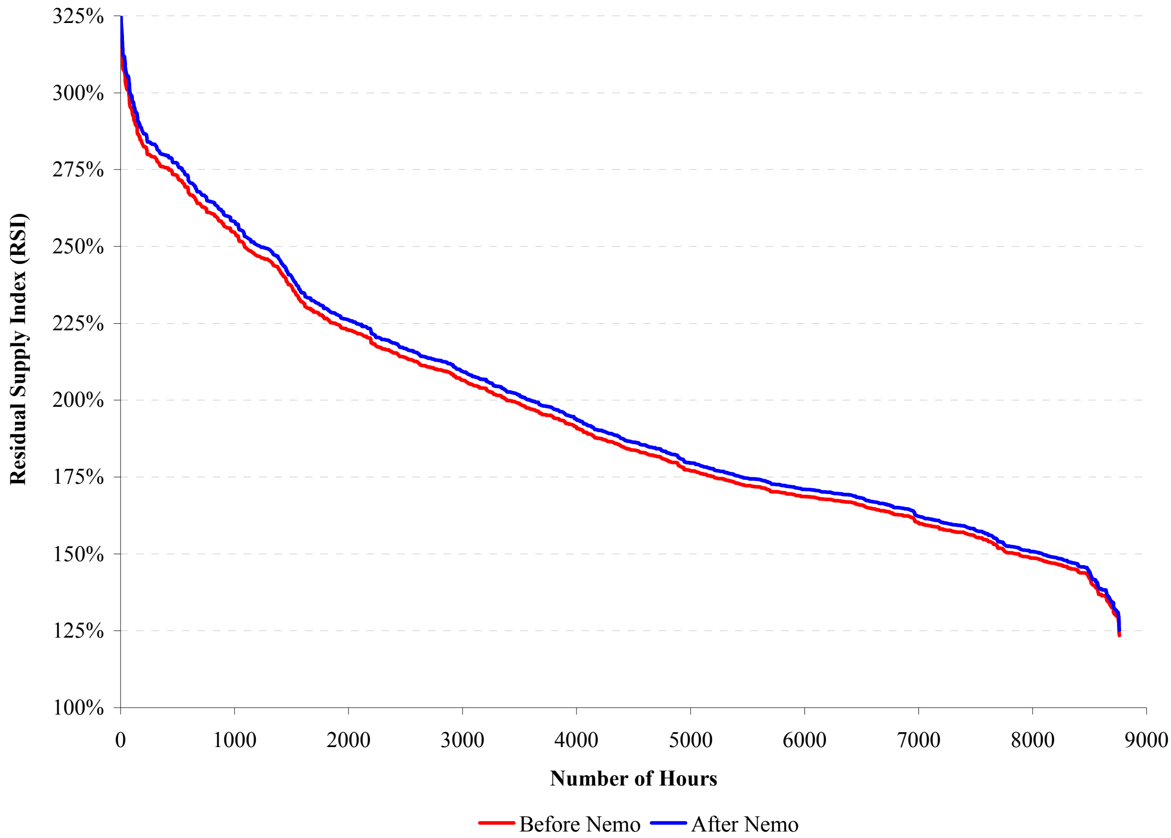
	Largest company Aallocation		Atomistic Competition	
	Before Nemo	After Nemo	Before Nemo	After Nemo
Concentration Ratios				
CR(1)	34%	35%	12%	12%
CR(3)	49%	49%	27%	27%
HHI Test				
HHI Value	1,492	1,541	515	502
ΔHHI		49		-13
Pivotal Supplier Test (% Hours Pivotal)				
RWE	1%	1%	0%	0%
Residual Supplier Test				
RWE				
Average	146%	146%	195%	198%
Maximum	240%	240%	320%	325%
Minimum	92%	92%	123%	125%

81. There is a pivotal supplier in the GB market for at most 1% of the year (see Table 7 above and Figure 29 below) and this conclusion does not change even if all the Nemo import capacity is controlled by the largest generator, RWE. The residual supply test in GB illustrates that the available capacity supplied by firms other than RWE is enough (on average) to meet demand levels approximately 50% above those we forecast under the largest company allocation scenario, and around 90% above forecast levels under the atomistic competition scenario.

82. The potential positive influence of the Nemo cable is smaller, due to the fact that it represents a smaller proportion of overall capacity. If the Nemo capacity is used by new independent players the HHI value in GB will decrease by about 13 points (or 2.4%). Figure 29 below illustrates the effect of the Nemo cable on the RSI values under the atomistic competition scenario in GB.[22] As expected, the RSI will increase if the Nemo additional transmission capacity is allocated to new independent firms. Its competitive effect on the RSI is however modest (relative to the effect in BE) at around 3%.

[22] As for the BE market, the Nemo project has no effect on the pivotality of RWE in the market for the largest company allocation scenario: the PSI and RSI measures are identical before and after the Nemo project is completed.

Figure 29: The effect of Nemo on the 2020 RSI in GB under the *atomistic competition* scenario



83. The Nemo project can increase the level of concentration in the GB market if all the Nemo capacity is allocated to RWE but, again, the impact is limited – under the largest company allocation scenario the HHI only increases by 49 points (or 3%). Consequently, according to the normal definitions, the GB market remains competitive. We have also estimated that it would be enough to ensure that no company can control more than 43% of the Nemo import capacity to ensure that the "after Nemo" HHI value remains identical to the "before Nemo" HHI. Again, this calculation represents the maximum mitigation measure that could be required, since the largest company allocation scenario is likely to over-estimate the proportion of new capacity that is built by RWE.

5.4 Summary

84. Under most plausible scenarios, the Nemo cable is like to have a positive impact on competition, particularly in BE. Moreover, a pro-competitive outcome can be guaranteed through a relatively simple mitigation measure that is already used for other cross-border capacity auctions[23] – namely limiting the proportion of the Nemo capacity that a single company can control. We calculate that, at most, it would be necessary to limit any company to controlling 43% of the Nemo capacity i.e.

[23] For example, on the BE-FR border/

sold by explicit auction – but this likely over-estimates the extent of mitigation that would be required.

Appendix I :Details of main model inputs

I.1. Demand

The project sponsors have provided us with forecasts of both peak demand (GW) and volume of demand (TWh), which we match. We derive a more detailed load shape from hourly 2008 demand.[24] We then apply a growth rate to the 2008 demand so that demand meets the forecasts peak load and volume. However, we recognise that the financial crisis have reduced demand in 2008 for the months September to December inclusive. This results in an unusual shape of demand in 2008, which should not be used to model future years. To correct the 2008 demand data financial crisis, for the period 2005-2009 we compared demand in each month to demand in the same month one year before. We then compared the fall in demand in the months of the financial crisis (defined as September to December 2008) to the largest fall seen before the financial crisis. Finally, as a simple correction for the financial crisis, we reasoned that any drop in demand in the months of the financial crisis which was larger than the biggest pre-crisis fall was due to the financial crisis. For example, in Belgium demand in December 2008 fell by about 9% compared to demand in December 2007. The largest pre-crisis annual fall in demand was only 4%. Therefore, we reasoned that about 5% of the fall was due to the financial crisis, and should be corrected. We then increased the December 2008 demand data for Belgium, so that the decrease relative to December 2007 was only 4%, the size of the largest pre-crisis decrease. While simplistic, this approach should correct for the worst effects of the financial crisis on demand in 2008.

Note that in most countries, the fall in demand seen in September to December 2008 was less than the largest pre-crisis fall in demand. For example, in Germany demand in December 2008 fell by about 3% compared to demand in December 2007. But the largest fall seen before the crisis was 5%. Hence we could not say with certainty that the fall seen in December 2008 demand in Germany was due to the financial crisis, rather than a structural change in the load shape. Accordingly we made no adjustment to 2008 German demand. On the basis of this methodology, the only adjustments we make are to increase 2008 Belgium demand by 4.58% in November and 5.82% in December. Table 8 illustrates peak volumes and demand in the base case for the countries and years modelled.

Table 8: Demand assumptions

Country	2020		2025		2030	
	Peak (GW)	Sales (TWh)	Peak (GW)	Sales (TWh)	Peak (GW)	Sales (TWh)
BE	16.2	101.6	16.8	105.8	17.2	108.2
FR	100.6	589.6	106.0	621.3	109.1	639.1
DE	99.8	615.7	104.4	643.8	107.3	661.8
NL	20.9	136.2	21.8	141.9	22.3	145.4
GB	57.2	329.6	56.8	326.9	55.9	322.0

[24] Note that we used 2008 demand data because this is what we used in a recent study for Elia. In the interests of efficiency, we did not update the demand shape to use 2009 data, but instead simply included an additional year of demand growth.

I.2. Gas and coal prices

BAM uses monthly fuel prices. In Figure 30 and Figure 31 below we illustrate the assumptions that we have used for the base case. The gas price assumptions were derived from a common starting point – the price for middle-eastern LNG (the "Suez price" – see Table 9). To this we added shipping costs and entry costs to derive country specific prices. We adjusted the LNG price so that the weighted average of the country prices (based on 2007 gas volumes) equalled the sponsors' gas price forecast.

Figure 30: Gas prices

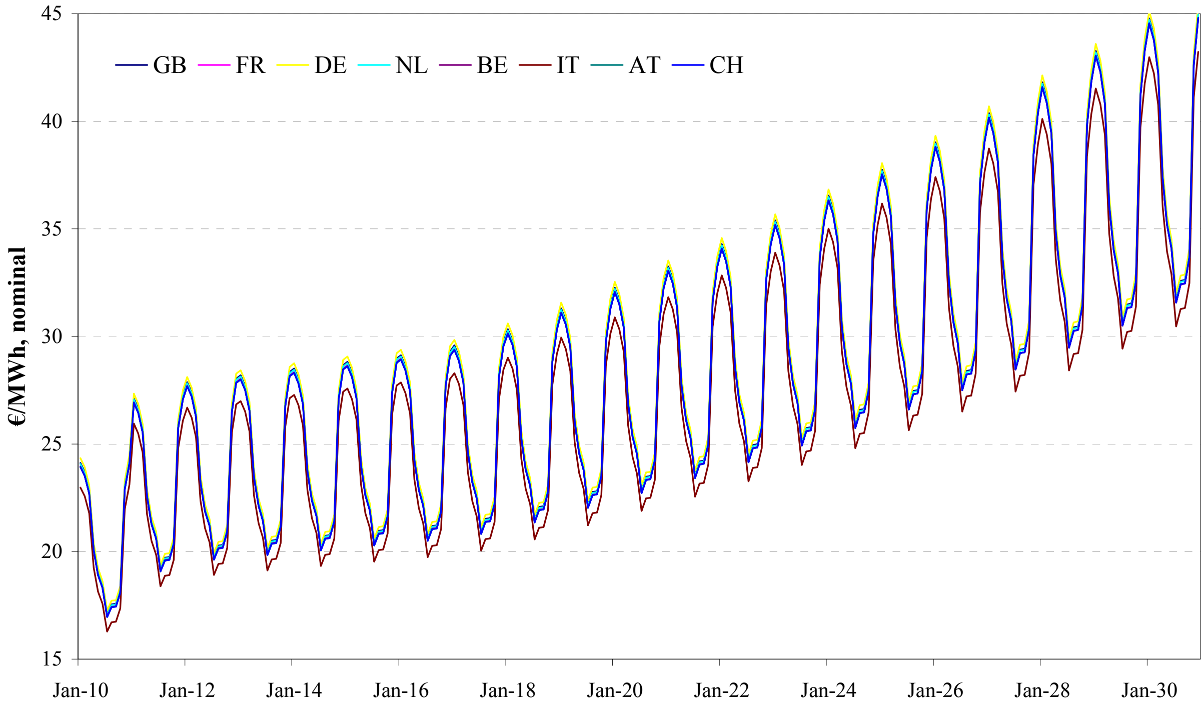
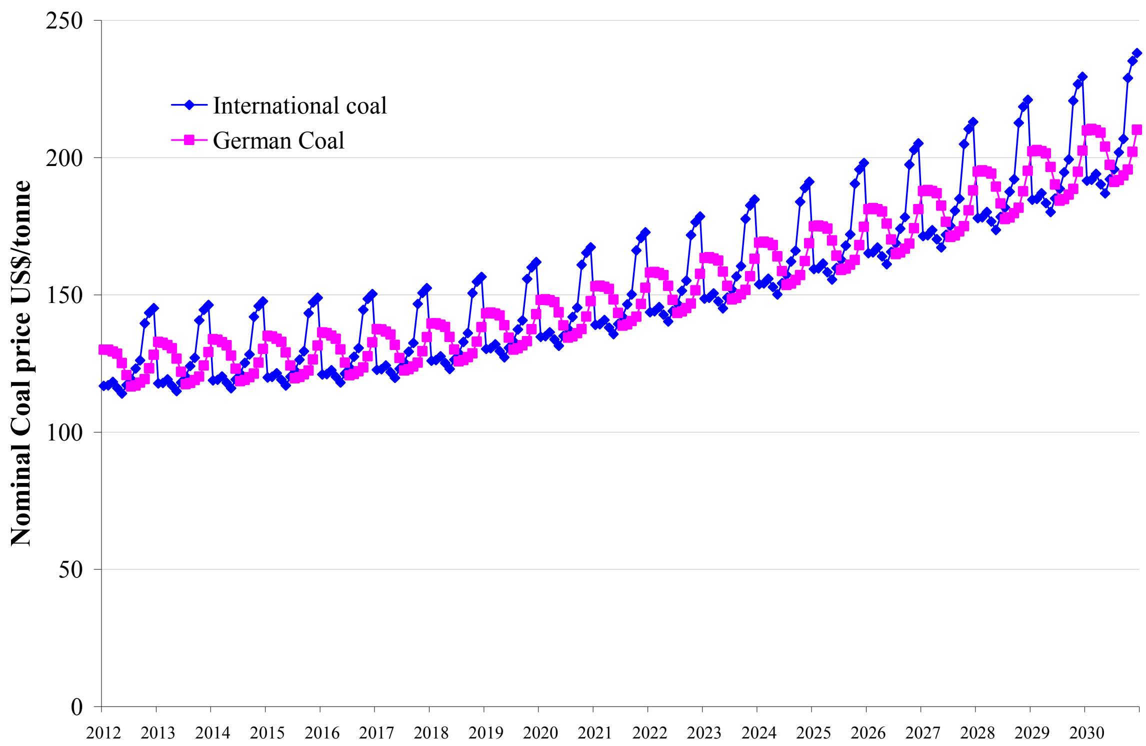


Table 9: Summary of annual gas price assumptions (€/MWh, nominal)

	2020	2025	2030
GB	27.45	32.11	38.09
FR	27.29	31.93	37.88
DE	27.68	32.36	38.37
NL	27.39	32.05	38.03
BE	27.28	31.93	37.89
"Suez price"	25.23	29.62	35.28
Weighted average	27.21	31.84	37.78
Elia price €/MWh	27.21	31.84	37.78

The annual average international coal prices shown in Figure 31 are based on data provided by the project sponsors whilst the seasonal pattern is based on an analysis of historical data from 2003 onwards. German domestic coal prices are obtained by averaging the previous six months of international coal prices. Lignite prices follow the same shapes as coal prices but are reduced by a factor of three beyond the reduction due to different calorific values in order to ensure that they operate at baseload.

Figure 31: Coal prices used, nominal



I.3. Base case merit orders

In this section we present the outturn annual average merit orders for the base case for GB and Belgium. This means that:

- the capacities used are the actual available capacities used in the model;
- the imports (price and volume) correspond to the annual average values results produced by the model; and
- the pumped storage generation and price correspond to the annual average values results produced by the model.

Figure 32: Belgian merit order 2020 – base case

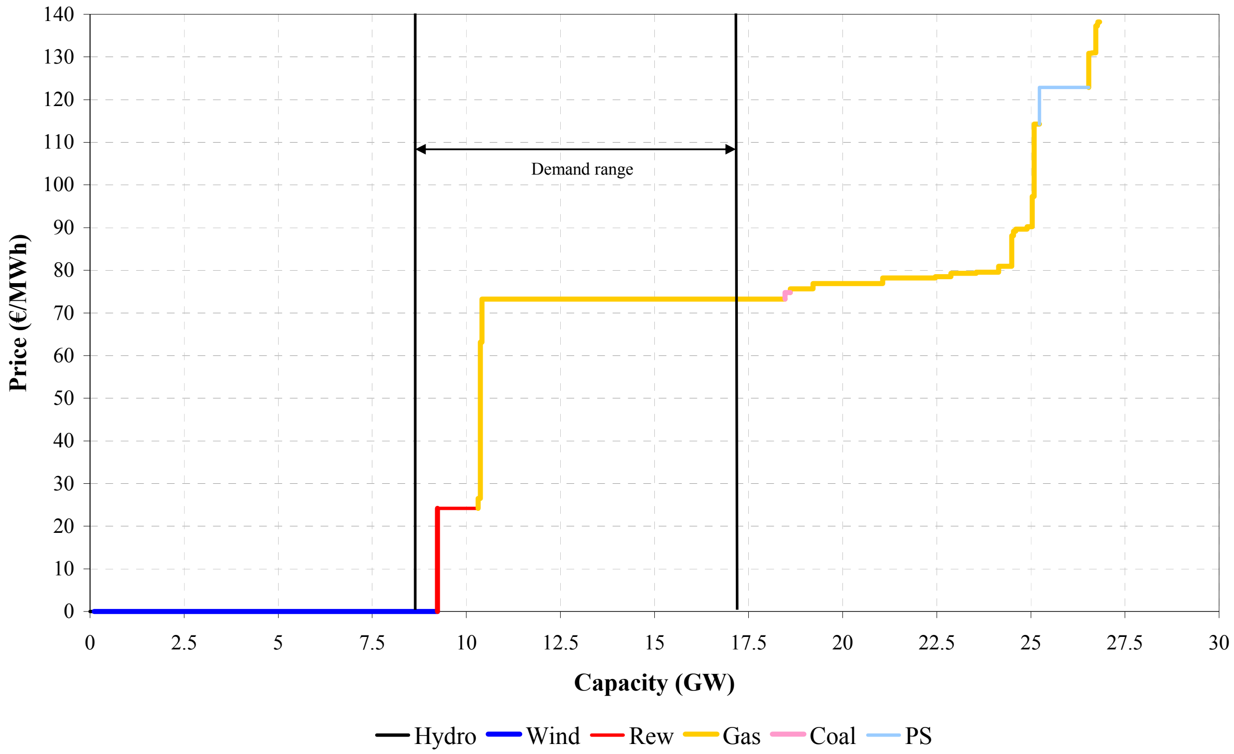


Figure 33: Belgian merit order 2025 – base case

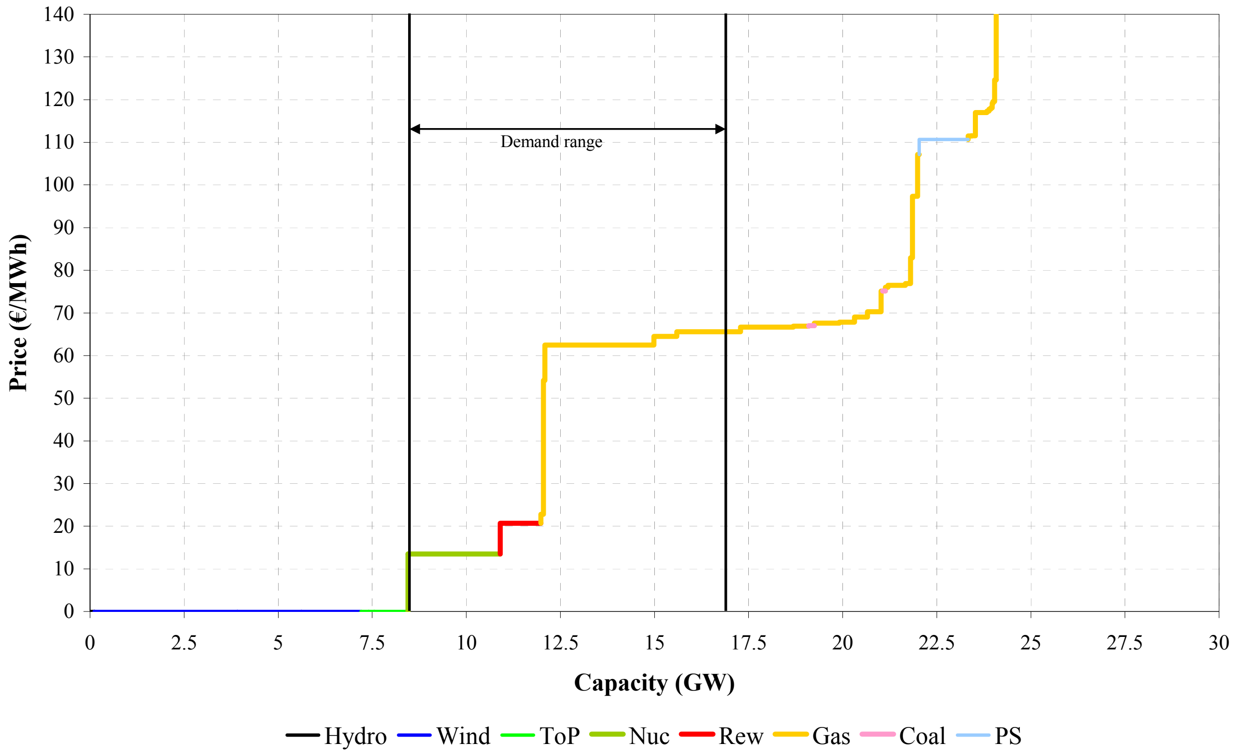


Figure 34: Belgian merit order 2030 – base case

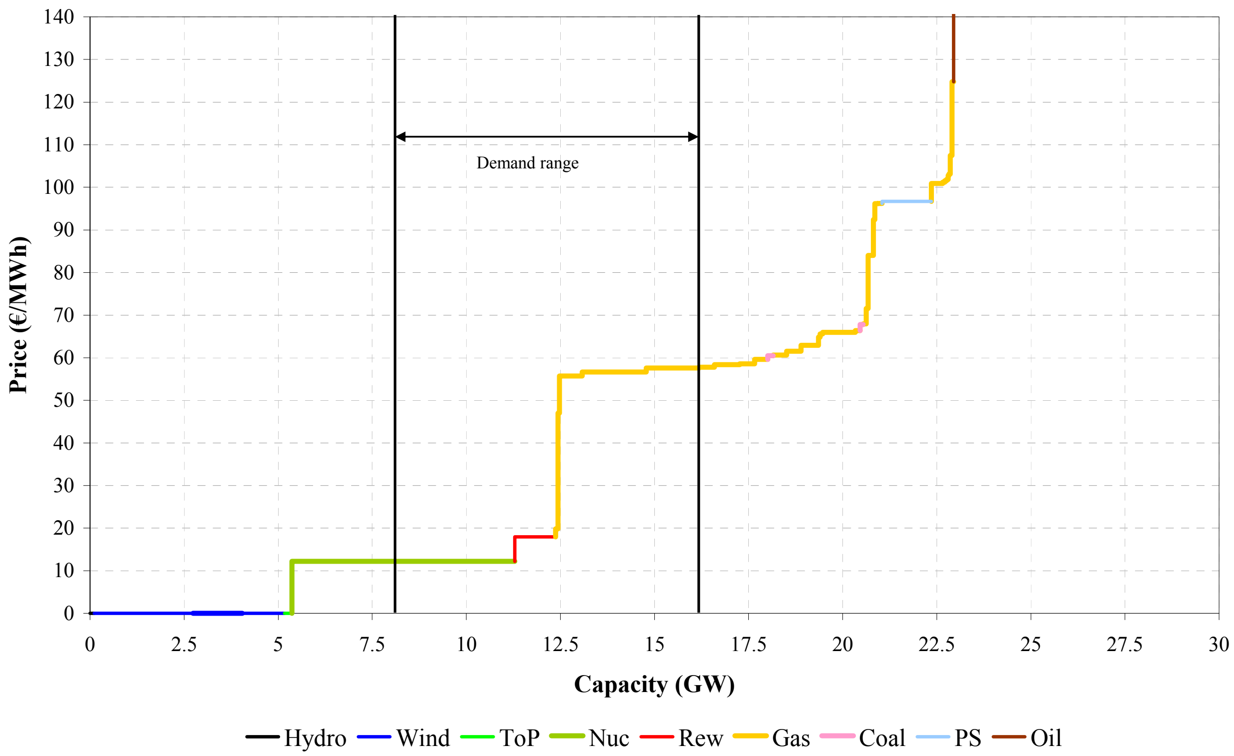


Figure 35: GB merit order 2020 – base case

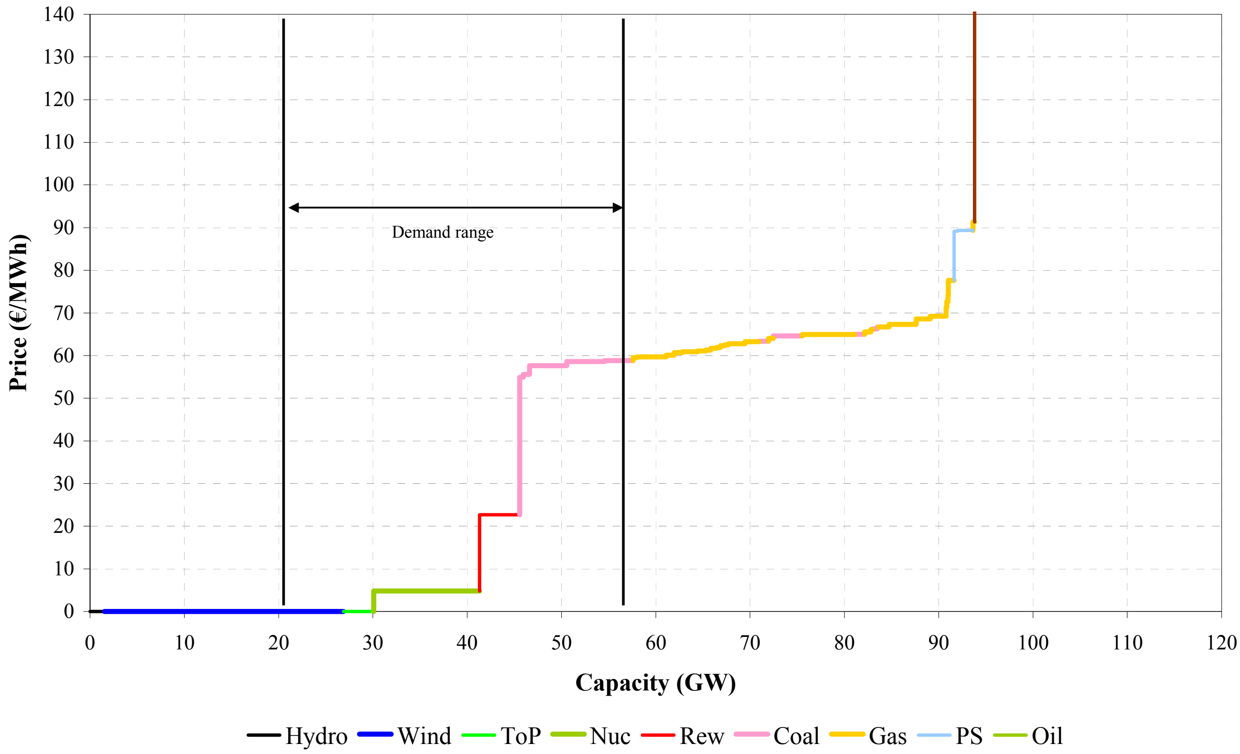


Figure 36: GB merit order 2025 – base case

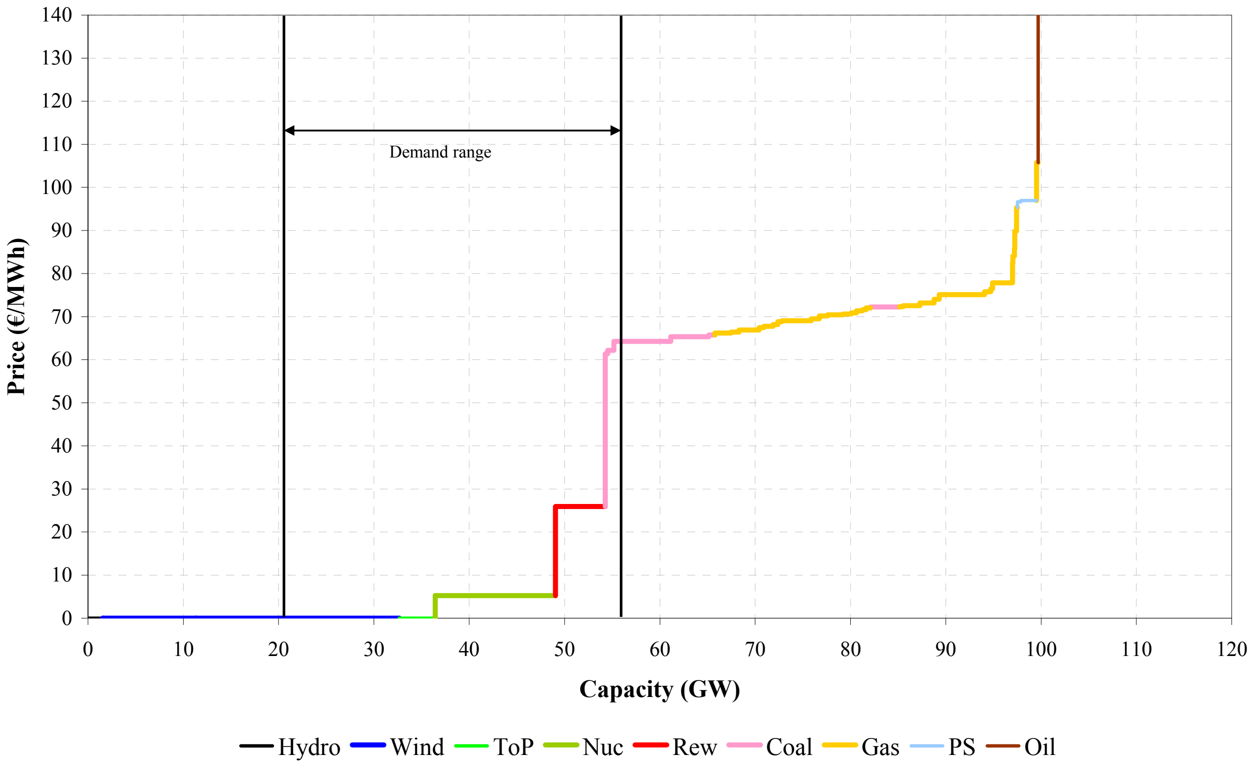
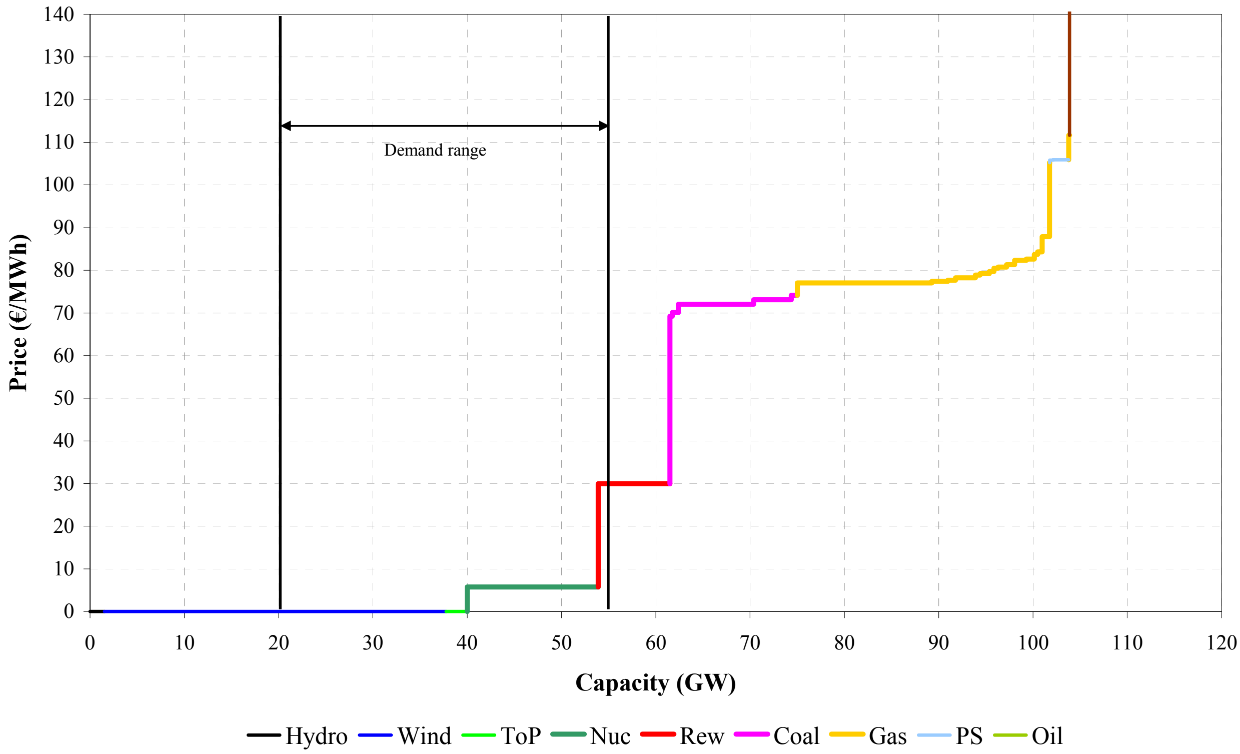


Figure 37: GB merit order 2030 – base case



I.4. Installed capacities

In this section, we present diagrams of the capacity assumptions in each of the cases modelled. The figures represent the capacities in the base case. The tables provide data for all the scenarios and sensitivities: if separate data for a scenario or sensitivity is not shown, this means that the capacity assumptions were the same as those in the base case (or extended scenario, as appropriate).

Figure 38: Base case installed capacity base case, Germany

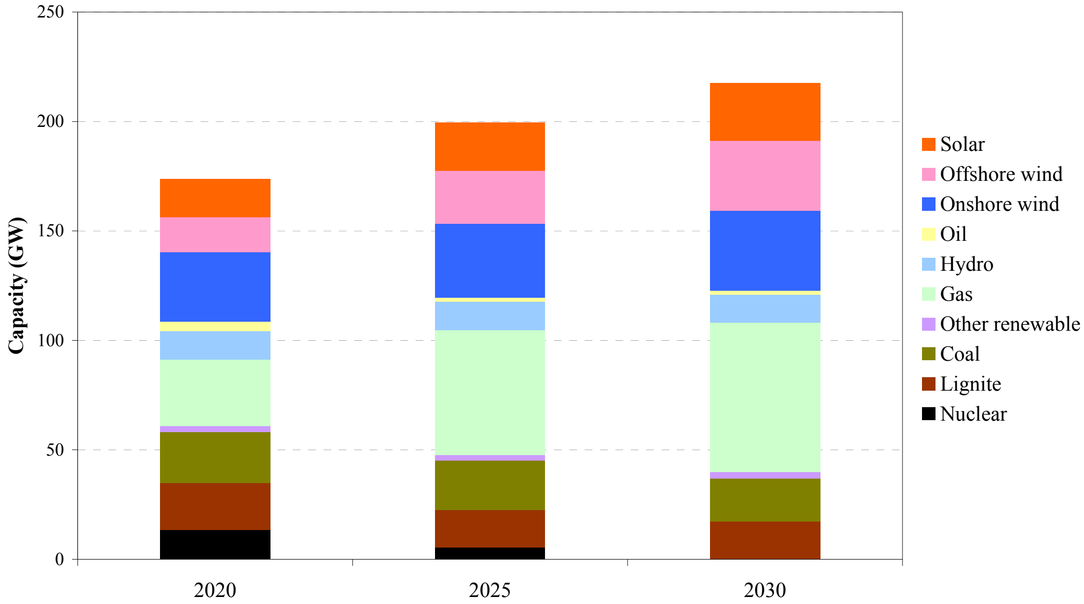


Table 10: Installed capacity in Germany by scenario (GW)

	Base case			Scenario 2/3			Scenario 4		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Additions									
Hydro	2.5	2.5	2.5	130.6	190.1	259.9	153.5	153.5	153.5
Coal	9.7	9.7	9.8	19.7	48.8	60.0	12.8	12.8	12.8
Gas	17.1	44.2	56.2	1.6	1.6	2.1	1.2	1.2	1.2
Lignite	5.4	5.4	5.4	0.0	0.0	0.0	3.5	3.5	3.5
Nuc	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Rew	9.7	9.7	9.8	19.6	48.7	59.9	12.7	12.7	12.7
Onshore	7.6	10.1	12.6	-0.3	1.6	3.5	7.6	10.1	12.6
Offshore	16.2	24.0	31.8	8.1	12.0	15.9	8.1	12.0	15.9
Solar	17.5	22.0	26.5	17.5	22.0	26.5	17.5	22.0	26.5
Retirements									
Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	9.2	10.1	12.9	18.0	48.2	61.8	13.2	13.2	13.2
Gas	4.2	4.6	5.6	-13.5	-42.3	-51.9	-6.7	-6.7	-6.7
Lignite	6.3	10.6	10.6	0.2	4.5	4.5	4.8	4.8	4.8
Nuc	7.1	15.0	20.5	7.1	15.0	20.5	3.6	3.6	3.6
Oil	0.3	3.0	3.2	0.4	3.1	3.3	2.3	2.3	2.3
Rew	8.0	8.1	7.6	17.9	47.1	57.8	11.4	11.4	11.4
Onshore	0	0	0	0	0	0	0	0	0
Offshore	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0
Installed capacity									
Hydro	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9
Coal	23.4	22.5	19.8	24.6	23.5	21.0	22.5	22.5	22.5
Gas	30.4	57.1	68.1	32.7	61.4	71.6	25.4	25.4	25.4
Lignite	21.5	17.1	17.1	22.2	17.8	17.8	21.0	21.0	21.0
Nuc	13.4	5.4	0.0	13.4	5.4	0.0	16.9	16.9	16.9
Oil	4.6	1.8	1.7	4.6	1.8	1.7	2.7	2.7	2.7
Rew	4.9	4.8	5.4	4.9	4.8	5.4	4.5	4.5	4.5
Onshore	31.5	34.0	36.5	23.6	25.5	27.4	31.5	34.0	36.5
Offshore	16.2	24.0	31.8	8.1	12.0	15.9	8.1	12.0	15.9
Solar	17.5	22.0	26.5	17.5	22.0	26.5	17.5	22.0	26.5

Figure 39: Base case installed capacity, Belgium

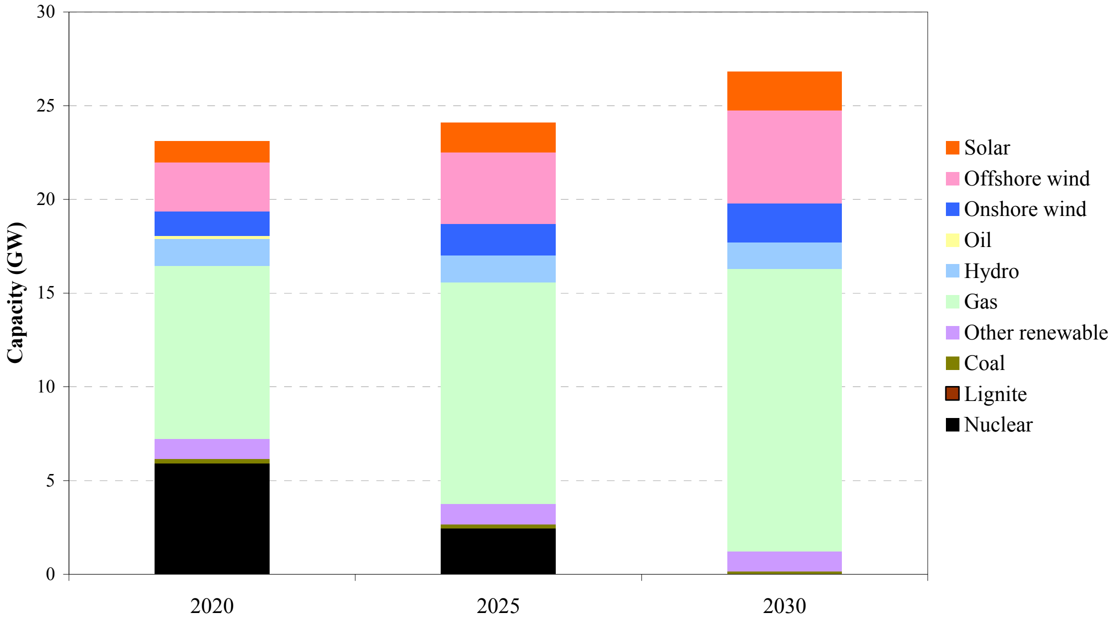


Table 11: Belgian capacity assumptions across all cases (GW)

	Base case			Scenario 2/3			Scenario 4			Sensitivity 1		
	2020	2025	2030	2020	2025	2030	2020	2025	2030	2020	2025	2030
Additions												
Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	4.0	8.0	12.2	4.3	8.4	12.7	4.0	4.9	8.2	4.0	8.0	12.2
Lignite												
Nuc	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rew	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4
Onshore	1.0	1.3	1.7	1.0	1.3	1.7	1.0	1.3	1.7	4.3	5.1	5.8
Offshore	2.6	3.8	4.9	1.8	2.6	3.5	2.6	3.8	4.9	2.6	3.8	4.9
Solar	1.1	1.6	2.1	1.1	1.6	2.1	1.1	1.6	2.1	1.1	1.6	2.1
Retirements												
Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	1.2	0.0	0.1	1.2	0.0	0.1	1.2	0.0	0.1	1.2	0.0	0.1
Gas	1.7	5.4	9.0	1.7	5.6	9.4	1.7	5.4	5.9	1.7	5.4	9.0
Lignite												
Nuc	0.0	3.5	2.5	0.0	3.5	2.5	0.0	0.4	1.4	0.0	3.5	2.5
Oil	0.2	0.2	0.0	0.2	0.2	0.0	0.2	0.2	0.0	0.2	0.2	0.0
Rew	0.2	0.5	0.5	0.2	0.5	0.5	0.2	0.5	0.5	0.9	0.4	0.4
Onshore	0	0	0	0	0	0	0	0	0	0	0	0
Offshore	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0
Installed capacity												
Hydro	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Coal	0.2	0.2	0.1	0.2	0.2	0.1	0.2	0.2	0.1	0.2	0.2	0.1
Gas	9.3	11.8	15.1	9.5	12.2	15.6	9.3	8.8	11.0	9.3	11.8	15.1
Lignite												
Nuc	5.9	2.5	0.0	5.9	2.5	0.0	5.9	5.5	4.1	5.9	2.5	0.0
Oil	0.2	0.0	0.0	0.2	0.0	0.0	0.2	0.0	0.0	0.2	0.0	0.0
Rew	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.4	0.4	0.4
Onshore	1.3	1.7	2.1	1.3	1.7	2.1	1.3	1.7	2.1	4.7	5.4	6.2
Offshore	2.6	3.8	5.0	1.8	2.7	3.5	2.6	3.8	5.0	2.6	3.8	5.0
Solar	1.1	1.6	2.1	1.1	1.6	2.1	1.1	1.6	2.1	1.1	1.6	2.1

Figure 40: Base case installed capacity, Netherlands

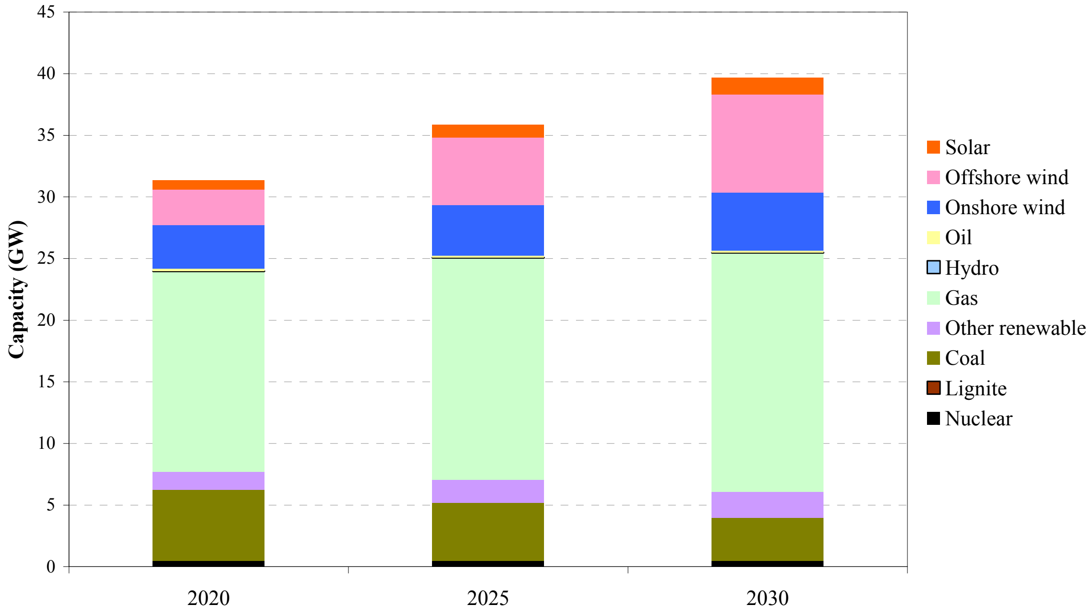


Table 12: Dutch capacity assumptions across all cases (GW)

	Base case			Scenario 2/3		
	2020	2025	2030	2020	2025	2030
Additions						
Hydro	0.0	0.0	0.0	0.0	0.0	0.0
Coal	2.5	2.7	2.7	2.5	2.7	2.7
Gas	7.1	9.9	11.7	7.6	10.6	12.7
Lignite						
Nuc	0.0	0.0	0.0	0.0	0.0	0.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0
Rew	0.3	0.6	0.9	0.3	0.7	1.1
Onshore	1.6	2.1	2.7	0.5	0.9	1.3
Offshore	2.7	5.2	7.7	1.8	3.6	5.3
Solar	0.7	1.1	1.4	0.7	1.1	1.4
Retirements						
Hydro	0.0	0.0	0.0	0.0	0.0	0.0
Coal	1.6	2.7	4.0	1.6	2.7	4.0
Gas	7.5	8.6	9.0	7.5	8.6	9.0
Lignite						
Nuc	0.0	0.0	0.0	0.0	0.0	0.0
Oil	0.0	0.1	0.1	0.0	0.1	0.1
Rew	0.0	0.0	0.0	0.0	0.0	0.0
Onshore	0	0	0	0	0	0
Offshore	0	0	0	0	0	0
Solar	0	0	0	0	0	0
Installed capacity						
Hydro	0.0	0.0	0.0	0.0	0.0	0.0
Coal	5.8	4.7	3.5	5.8	4.7	3.5
Gas	16.2	18.0	19.4	16.7	18.7	20.4
Lignite						
Nuc	0.5	0.5	0.5	0.5	0.5	0.5
Oil	0.2	0.2	0.2	0.2	0.2	0.2
Rew	1.5	1.8	2.1	1.6	1.9	2.3
Onshore	3.5	4.1	4.7	2.5	2.9	3.3
Offshore	2.9	5.4	8.0	2.0	3.8	5.6
Solar	0.7	1.1	1.4	0.7	1.1	1.4

Figure 41: Base case installed capacity, France

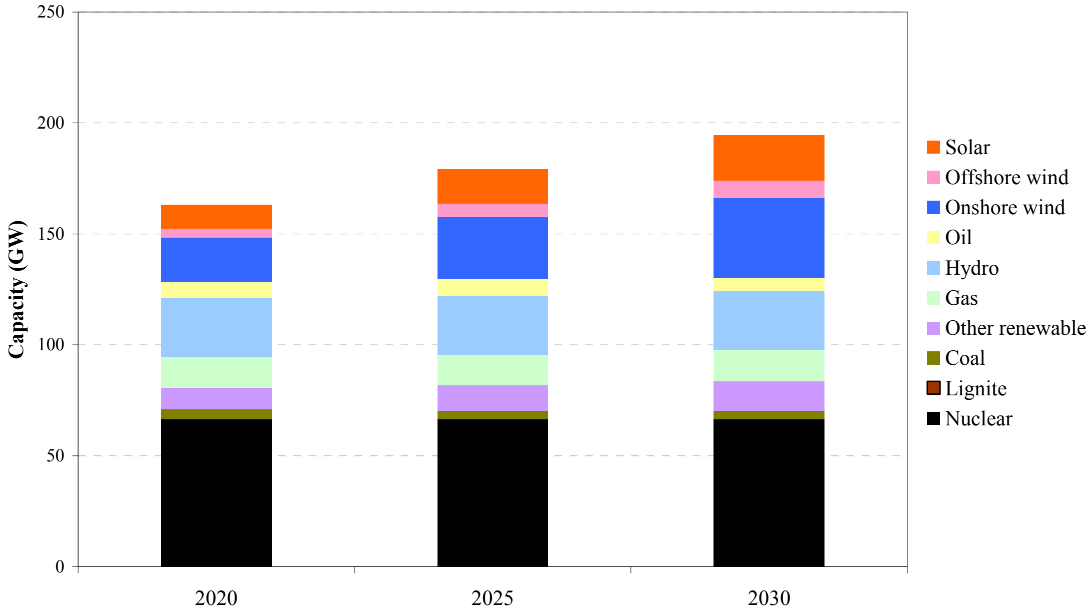


Table 13: French capacity assumptions across all cases (GW)

	Base case			Scenario 2/3		
	2020	2025	2030	2020	2025	2030
Additions						
Hydro	0.0	0.0	0.0	54.5	93.8	145.0
Coal	0.7	0.7	0.7	18.8	19.3	21.1
Gas	17.3	17.3	18.5	0.7	0.7	0.7
Lignite						
Nuc	3.2	3.2	3.2	5.7	5.7	5.7
Oil	4.1	4.1	4.1	7.1	10.0	12.3
Rew	9.3	11.0	12.8	3.1	3.1	3.1
Onshore	16.5	24.6	32.7	10.5	10.5	10.5
Offshore	4.0	6.0	8.0	2.8	2.8	2.8
Solar	10.5	15.5	20.4	10.5	10.5	10.5
Retirements						
Hydro	0.0	0.0	0.0	54.5	93.8	145.0
Coal	6.1	6.7	6.7	24.2	25.3	27.0
Gas	6.4	6.4	7.2	-11.7	-12.2	-13.1
Lignite						
Nuc	0.0	0.0	0.0	2.5	2.5	2.5
Oil	5.3	5.3	7.1	8.3	11.2	15.3
Rew	0.7	0.7	0.7	-5.5	-8.4	-10.7
Onshore	0	0	0	0	0	0
Offshore	0	0	0	0	0	0
Solar	0	0	0	0	0	0
Installed capacity						
Hydro	26.5	26.5	26.5	26.5	26.5	26.5
Coal	4.5	3.9	3.9	4.5	3.9	3.9
Gas	13.8	13.8	14.2	15.3	15.8	16.8
Lignite						
Nuc	66.5	66.5	66.5	66.5	66.5	66.5
Oil	7.6	7.6	5.7	7.6	7.6	5.7
Rew	9.7	11.3	13.2	9.7	12.6	14.9
Onshore	19.9	28.0	36.1	13.9	13.9	13.9
Offshore	4.0	6.0	8.0	2.8	2.8	2.8
Solar	19.3	25.9	32.7	19.3	22.2	24.5

Figure 42: Base case installed capacity, GB

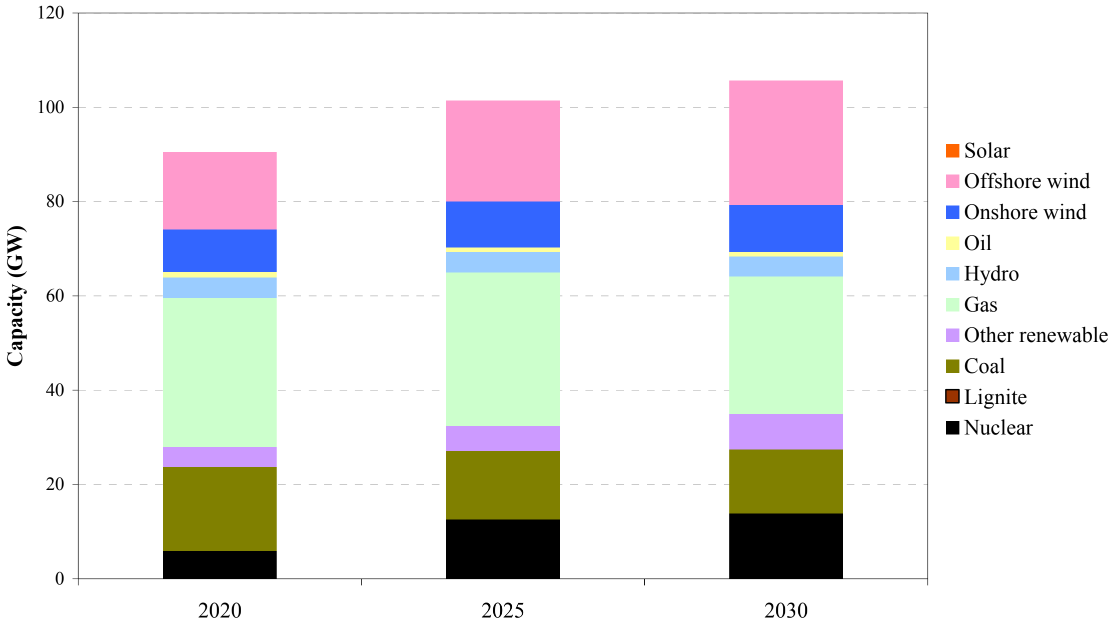


Table 14: GB capacity assumptions across all cases (GW)

	Base case			Scenario 2/3			Scenario 4		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Additions									
Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	8.0	10.0	12.0	8.0	10.0	12.0	8.0	10.0	12.0
Gas	7.5	15.4	30.2	8.6	16.6	31.3	7.5	15.4	30.2
Lignite									
Nuc	1.2	10.2	12.7	1.2	10.2	12.7	6.5	10.2	12.7
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rew	5.6	6.6	9.0	5.6	6.9	9.5	5.6	6.6	9.0
Onshore	6.3	7.1	7.2	5.0	5.6	5.7	6.3	7.1	7.2
Offshore	15.8	20.8	25.8	13.3	17.6	21.8	15.8	20.8	25.8
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Retirements									
Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	20.3	25.6	28.6	20.3	13.2	13.0	20.3	13.2	13.0
Gas	5.5	12.5	30.8	5.5	15.6	34.9	5.5	14.4	33.8
Lignite									
Nuc	6.1	8.5	9.7	6.1	3.5	11.4	6.1	8.8	11.4
Oil	5.7	5.9	5.9	5.7	0.2	0.0	5.7	0.2	0.0
Rew	3.3	3.3	3.3	3.3	5.6	6.9	3.3	5.6	6.6
Onshore	0	0	0	0	0	0	0	0	0
Offshore	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0
Installed capacity									
Hydro	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Coal	17.8	14.6	13.5	17.8	14.6	13.5	17.8	14.6	13.5
Gas	31.6	32.6	29.1	32.7	33.7	30.2	31.6	32.6	29.1
Lignite									
Nuc	5.9	12.6	13.9	5.9	12.6	13.9	11.3	12.6	13.9
Oil	1.2	1.0	1.0	1.2	1.0	1.0	1.2	1.0	1.0
Rew	4.3	5.2	7.6	4.3	5.5	8.2	4.3	5.2	7.6
Onshore	9.0	9.8	9.9	7.6	8.3	8.4	9.0	9.8	9.9
Offshore	16.4	21.4	26.4	13.9	18.2	22.4	16.4	21.4	26.4
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

I.5. Net transfer capacity assumed

Table 15 and Table 16 present the winter (Dec-Feb) and summer (Apr-Oct) interconnector values assumed for the borders modelled in detail. (Note that these tables show the “with cable” case – for the “without” cable case, we assume a Nemo interconnector capacity of 200 MW). For the “shoulder” months (Mar and Nov), we use values equal to the average of the winter and summer figures.

Table 15: Winter NTC values used (MW)

From:	To: FR	BE	DE	NL	GB	Total exports
FR		3,652	2,900		3,000	9,552
BE	2,022		1,000	1,431	1,000	5,452
DE	2,750	1,000		4,850		8,600
NL		1,332	4,000		1,000	6,332
GB	3,000	1,000		1,000		5,000
Total imports	7,772	6,983	7,900	7,281	5,000	

Table 16: Summer NTC values used (MW)

From:	To: FR	BE	DE	NL	GB	Total exports
FR		2,582	2,400		3,000	7,982
BE	1,564		1,000	1,426	1,000	4,990
DE	2,700	1,000		5,000		8,700
NL		1,332	4,000		1,000	6,332
GB	3,000	1,000		1,000		5,000
Total imports	7,264	5,914	7,400	7,426	5,000	

For borders that we do not model in details, we use a combination of methods. For most borders, we fix the cross-border flows at the levels seen in 2009. However, for NordPool, the Czech Republic and Poland we allow flows to vary over time. We assume that prices in these markets will develop over time from their 2008 values in line with developments in the marginal costs of coal plants (which typically set prices in these countries[25]), allowing for the impact of losses where appropriate. Accordingly, to the extent that prices in the core countries model in detail develop in a different manner, the pattern of flows into and out of these three countries will change over time.

[25] In NordPool this is true only when hydro conditions are normal and Danish coal plant play an important role in price setting. For this project, we have concentrated upon modelling only normal hydro conditions.

Appendix II : Detailed Results

II.1.Base case

Table 17: ***Base case*** **median changes in welfare, € million (2009 money)**

	Consumer welfare			Producer welfare			Overall welfare		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
BE	15.0	12.7	-22.3	18.1	0.1	32.3	33.6	13.0	10.1
NL	-0.6	-2.8	-2.7	0.9	3.9	3.6	0.3	1.2	1.0
DE	6.7	-0.8	-11.2	-6.5	0.9	11.4	0.2	0.1	0.3
GB	-33.9	-106.5	85.2	36.4	125.8	-58.8	2.7	19.1	26.7
FR	-16.0	-25.9	19.8	16.5	27.2	-19.0	0.5	1.0	0.8
Total	-28.9	-123.3	68.8	65.3	158.0	-30.4	37.3	34.5	38.9

II.2.Scenario 1

Table 18: ***Scenario 1*** **median congestion revenues, € million (2009 money)**

	With GB-BE cable			Without GB-BE cable			Change (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
FR to GB	260.8	359.3	479.7	263.2	370.0	490.2	-2.4	-10.3	-10.4
BE to FR	85.4	132.1	177.2	92.6	134.6	179.3	-7.2	-2.5	-2.0
DE to FR	100.9	146.7	178.4	101.0	147.1	178.8	-0.2	-0.5	-0.5
NL to DE	187.7	209.8	183.6	188.3	210.1	184.3	-0.6	-0.3	-0.7
NL to BE	53.7	68.2	80.1	61.1	71.6	83.4	-7.5	-3.4	-3.3
NL to GB	58.7	77.2	108.6	60.5	83.0	114.5	-1.8	-5.8	-5.7
DE to BE	41.6	46.5	55.1	43.0	47.7	55.8	-1.4	-1.1	-0.8
GB to BE	65.0	81.3	115.4	0.0	0.0	0.0	**65.0**	**81.3**	**115.4**
Total	853.9	1121.0	1378.1	809.8	1064.1	1286.3	44.1	57.0	91.7

Table 19: ***Scenario 1*** **median TSO revenues, € million (2009 money)**

	With GB-BE cable			Without GB-BE cable			Change (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Unadjusted									
BE	197.2	272.2	355.2	179.1	237.6	302.8	18.0	37.0	54.7
GB	192.3	258.9	351.8	161.9	226.5	302.3	30.5	32.5	49.5
Adjusted									
BE	122.9	164.0	213.9	98.4	126.9	159.3	24.5	37.1	54.6
GB	192.3	258.9	351.8	161.9	226.5	302.3	30.4	32.4	49.5

Table 20: *Scenario 1* median cross-border flows, TWh

With GB-BE cable

From:	To: FR	BE	DE	NL	GB	Total exports
2020						
FR		14.8	13.7		16.4	44.9
BE	6.9		4.7	7.4	4.7	23.7
DE	3.0	4.1		15.7		22.7
NL		5.3	4.3		4.4	13.9
GB	5.8	1.9		2.4		10.1
Total imports	15.8	26.0	22.7	25.5	25.4	
2025						
FR		14.9	14.4		11.2	40.5
BE	6.7		5.1	6.7	2.5	21.0
DE	8.4	3.7		17.2		29.3
NL		5.9	25.2		2.5	33.6
GB	11.1	4.0		4.4		19.5
Total imports	26.3	28.5	44.6	28.3	16.2	
2030						
FR		15.0	14.4		10.6	40.0
BE	6.5		5.1	6.6	2.4	20.5
DE	8.5	3.7		17.6		29.7
NL		6.1	24.7		2.4	33.2
GB	12.5	4.9		5.0		22.4
Total imports	27.5	29.7	44.2	29.2	15.4	

Without GB-BE cable

From:	To: FR	BE	DE	NL	GB	Total exports
2020						
FR		14.5	13.7		16.3	44.5
BE	7.1		4.8	7.6	0.0	19.5
DE	3.0	4.0		15.7		22.7
NL		5.0	4.3		4.4	13.7
GB	6.0	0.0		2.4		8.4
Total imports	16.1	23.6	22.8	25.7	20.6	
2025						
FR		15.0	14.4		11.2	40.6
BE	6.7		5.0	6.6	0.0	18.3
DE	8.4	3.8		17.3		29.4
NL		6.1	25.1		2.5	33.7
GB	11.2	0.0		4.4		15.6
Total imports	26.3	24.8	44.6	28.2	13.7	
2030						
FR		15.1	14.4		10.6	40.0
BE	6.4		5.1	6.5	0.0	18.0
DE	8.5	3.7		17.6		29.7
NL		6.1	24.7		2.5	33.3
GB	12.6	0.0		5.0		17.5
Total imports	27.5	24.9	44.1	29.1	13.1	

Difference (with minus without)

From:	To: FR	BE	DE	NL	GB	Total exports
2020						
FR		0.3	0.0		0.1	0.4
BE	-0.2		**-0.1**	-0.2	4.7	4.2
DE	0.0	**0.1**		0.0		0.1
NL		0.2	0.0		0.0	0.2
GB	-0.1	1.9		-0.1		1.7
Total imports	-0.3	2.5	-0.1	-0.3	4.8	
2025						
FR		-0.1	0.0		0.1	-0.1
BE	0.0		**0.1**	0.2	2.5	2.7
DE	0.0	**-0.1**		0.0		-0.1
NL		-0.2	0.0		0.0	-0.2
GB	-0.1	4.0		0.0		3.9
Total imports	0.0	3.7	0.0	0.1	2.5	
2030						
FR		0.0	0.0		0.0	0.0
BE	0.0		**0.0**	0.1	2.4	2.5
DE	0.0	**0.0**		0.0		0.0
NL		-0.1	0.0		-0.1	-0.1
GB	0.0	4.9		0.0		4.9
Total imports	0.0	4.8	0.0	0.1	2.3	

Table 21: *Scenario 1* median baseload prices, €/MWh (2009 money)

	With GB-BE cable			Without GB-BE cable			Difference (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Germany	51.69	54.40	56.13	51.72	54.40	56.11	-0.03	0.00	0.01
Belgium	51.16	54.32	56.07	51.30	54.47	55.95	-0.14	-0.15	0.12
France	49.20	50.45	51.76	49.23	50.36	51.68	-0.02	0.09	0.08
Netherlands	52.46	53.85	55.18	52.47	53.85	55.14	-0.01	0.00	0.04
GB	53.89	50.20	49.46	53.84	49.83	49.11	0.06	0.37	0.35
GB minus BE	2.73	-4.12	-6.61	2.53	-4.63	-6.84	0.20	0.52	0.23
BE minus FR	1.95	3.87	4.31	2.07	4.10	4.27	-0.12	-0.23	0.04

Table 22: *Scenario 1* median welfare changes, € million (2009 money)

	Consumer welfare			Producer welfare			Overall welfare		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
BE	19.7	14.7	-17.3	14.2	-0.8	29.4	33.9	13.8	11.7
NL	1.6	-1.3	-5.8	-0.9	2.1	6.9	0.7	0.7	1.1
DE	22.7	-0.9	-13.0	-22.4	1.1	13.1	0.2	0.3	0.2
GB	-26.2	-108.9	-92.2	29.7	125.8	111.5	3.7	16.7	18.9
FR	20.9	-49.0	-48.3	-20.7	50.1	49.5	0.2	1.0	1.3
Total	38.7	-145.4	-176.6	-0.1	178.4	210.5	38.7	32.5	33.1

II.3.Scenario 2

Table 23: *Scenario 2* median congestion rents, € million (2009 money)

	With GB-BE cable			Without GB-BE cable			Change (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
FR to GB	212.0	279.0	375.5	213.1	288.3	389.3	-1.1	-9.5	-13.8
BE to FR	70.0	102.5	130.4	77.4	103.9	131.8	-7.5	-1.4	-1.4
DE to FR	88.3	115.3	128.8	88.5	115.4	129.1	-0.2	-0.2	-0.2
NL to DE	191.6	204.0	186.1	191.8	204.4	187.7	-0.1	-0.4	-1.6
NL to BE	50.5	65.9	75.3	57.7	68.4	77.3	-7.3	-2.5	-2.0
NL to GB	58.1	66.9	98.4	59.4	71.5	104.5	-1.3	-4.6	-6.1
DE to BE	44.8	42.6	46.0	46.0	43.3	46.5	-1.2	-0.7	-0.5
GB to BE	61.8	66.0	100.2	0.0	0.0	0.0	**61.8**	**66.0**	**100.2**
Total	777.1	942.2	1140.8	733.9	895.2	1066.1	43.2	47.0	74.7

Table 24: *Scenario 2* median TSO revenues, € million (2009 money)

	With GB-BE cable			Without GB-BE cable			Change (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Unadjusted									
BE	178.0	226.4	284.4	161.5	197.2	237.7	16.4	30.9	48.1
GB	166.0	206.0	287.1	136.2	179.9	246.9	29.7	25.9	40.2
Adjusted									
BE	113.5	138.5	176.0	90.6	107.8	127.8	23.0	30.7	48.2
GB	166.0	206.0	287.1	136.2	179.9	246.9	29.7	26.0	40.2

Table 25: *Scenario 2* median cross-border flows, TWh

With GB-BE cable

	To					Total
From:	FR	BE	DE	NL	GB	exports
2020						
FR		14.9	13.1		16.2	44.2
BE	7.0		4.5	6.8	4.5	22.8
DE	2.9	4.3		15.3		22.4
NL		5.8	3.5		4.4	13.8
GB	5.4	1.8		2.2		9.4
Total imports	15.3	26.8	21.1	24.3	25.1	
2025						
FR		14.6	13.8		10.9	39.4
BE	6.9		4.8	6.4	2.4	20.5
DE	9.1	3.9		18.5		31.5
NL		6.3	24.2		2.6	33.1
GB	10.9	3.9		4.1		18.9
Total imports	26.9	28.8	42.8	28.9	15.8	
2030						
FR		14.3	13.7		9.2	37.2
BE	6.9		4.9	6.4	2.2	20.4
DE	9.2	3.8		17.5		30.5
NL		6.3	24.9		2.2	33.4
GB	13.7	5.0		5.2		23.9
Total imports	29.9	29.5	43.5	29.0	13.6	

Without GB-BE cable

	To					Total
From:	FR	BE	DE	NL	GB	exports
2020						
FR		14.6	13.2		16.1	43.8
BE	7.2		4.6	7.1	0.0	18.9
DE	2.9	4.2		15.3		22.4
NL		5.5	3.6		4.4	13.4
GB	5.5	0.0		2.2		7.7
Total imports	15.6	24.3	21.3	24.7	20.5	
2025						
FR		14.7	13.8		10.9	39.4
BE	6.9		4.8	6.2	0.0	17.9
DE	9.1	4.0		18.5		31.5
NL		6.5	24.2		2.6	33.2
GB	11.1	0.0		4.1		15.2
Total imports	27.1	25.1	42.8	28.8	13.4	
2030						
FR		14.3	13.6		9.3	37.2
BE	6.9		5.0	6.3	0.0	18.2
DE	9.3	3.8		17.6		30.7
NL		6.4	24.8		2.3	33.5
GB	13.7	0.0		5.1		18.8
Total imports	29.9	24.4	43.4	29.0	11.6	

Difference (with minus without)						
	To					Total
From:	FR	BE	DE	NL	GB	exports
2020						
FR		0.3	0.0		0.1	0.4
BE	-0.2		**-0.1**	-0.3	4.5	3.9
DE	0.0	**0.1**		0.0		0.0
NL		0.3	0.0		0.1	0.3
GB	-0.1	1.8		-0.1		1.7
Total imports	-0.3	2.5	-0.2	-0.4	4.7	
2025						
FR		0.0	0.0		0.1	0.0
BE	0.0		**0.0**	0.1	2.4	2.5
DE	0.0	**0.0**		0.0		0.0
NL		-0.2	0.0		0.0	-0.2
GB	-0.1	3.9		0.0		3.7
Total imports	-0.1	3.6	0.0	0.1	2.4	
2030						
FR		0.0	0.1		-0.1	0.0
BE	0.0		**0.0**	0.0	2.2	2.2
DE	-0.1	**0.0**		-0.1		-0.2
NL		-0.1	0.0		-0.1	-0.1
GB	0.0	5.0		0.1		5.2
Total imports	-0.1	5.0	0.1	0.1	2.0	

Table 26: *Scenario 2* median baseload prices, €/MWh (2009 money)

	With GB-BE cable			Without GB-BE cable			Difference (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Germany	51.67	54.17	55.82	51.70	54.17	55.80	-0.02	0.01	0.01
Belgium	51.51	54.27	55.82	51.55	54.39	55.67	-0.04	-0.13	0.16
France	49.88	51.23	52.77	49.88	51.20	52.83	0.00	0.04	-0.06
Netherlands	52.37	53.77	55.31	52.37	53.74	55.27	0.00	0.03	0.04
GB	53.65	51.06	49.85	53.60	50.80	49.79	0.05	0.26	0.06
GB minus BE	2.15	-3.20	-5.97	2.06	-3.59	-5.88	0.09	0.39	-0.09
BE minus FR	1.62	3.03	3.05	1.66	3.20	2.84	-0.04	-0.16	0.21

Table 27: *Scenario 2* median welfare changes, € million (2009 money)

	Consumer welfare			Producer welfare			Overall welfare		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
BE	5.0	11.1	-22.6	28.4	-1.5	31.5	33.6	9.5	9.0
NL	0.8	-3.8	-6.7	-0.5	4.7	8.2	0.3	0.9	1.5
DE	16.6	-1.7	-9.1	-16.4	1.7	9.8	0.2	0.0	0.6
GB	-26.3	-69.3	-0.1	28.1	83.7	23.7	1.8	14.3	23.6
FR	1.4	-20.0	47.9	-1.1	20.6	-47.4	0.2	0.5	0.5
Total	-2.5	-83.7	9.4	38.6	109.3	25.8	36.2	25.2	35.2

II.4.Scenario 3

Table 28: *Scenario 3* median congestion rents, € million (2009 money)

	With GB-BE cable			Without GB-BE cable			Change (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
FR to GB	207.8	273.7	348.3	209.2	281.3	358.6	-1.4	-7.6	-10.5
BE to FR	69.2	102.4	128.0	75.9	102.7	128.3	-6.6	-0.4	-0.3
DE to FR	84.9	105.3	126.1	85.1	105.4	126.4	-0.2	-0.1	-0.3
NL to DE	178.2	143.9	156.1	178.9	143.9	156.1	-0.7	-0.1	-0.1
NL to BE	50.7	65.8	74.1	58.0	66.4	75.1	-7.3	-0.6	-1.1
NL to GB	54.3	69.0	85.7	55.8	73.1	90.8	-1.4	-4.1	-5.0
DE to BE	39.4	42.2	47.0	40.1	43.0	46.9	-0.7	-0.8	0.0
GB to BE	57.9	68.8	84.8	0.0	0.0	0.0	**57.9**	**68.8**	**84.8**
Total	742.5	871.0	1050.1	703.0	815.8	982.3	39.5	55.2	67.8

Table 29: *Scenario 3* median TSO revenues, € million (2009 money)

	With GB-BE cable			Without GB-BE cable			Change (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Unadjusted									
BE	171.5	227.4	273.8	155.7	194.4	232.4	15.8	33.4	42.1
GB	160.0	205.8	259.4	132.5	177.2	224.7	27.6	28.5	34.7
Adjusted									
BE	108.6	139.6	166.9	87.0	106.1	125.2	21.6	33.5	41.8
GB	160.0	205.8	259.4	132.5	177.2	224.7	27.5	28.6	34.7

Table 30: *Scenario 3* median cross-border flows, TWh

With GB-BE cable

	To					Total
From:	FR	BE	DE	NL	GB	exports
2020						
FR		14.8	13.8		16.4	45.0
BE	7.0		4.8	7.4	4.6	23.8
DE	2.6	4.0		14.5		21.2
NL		5.2	3.8		4.4	13.4
GB	5.3	1.7		2.2		9.2
Total imports	15.0	25.8	22.3	24.1	25.5	
2025						
FR		15.0	14.5		11.4	40.9
BE	6.7		5.1	6.9	2.5	21.1
DE	8.3	3.7		17.2		29.2
NL		5.8	25.2		2.5	33.5
GB	10.5	3.9		4.2		18.5
Total imports	25.5	28.3	44.7	28.3	16.4	
2030						
FR		14.2	13.9		10.6	38.6
BE	7.0		5.1	6.6	2.4	21.1
DE	9.1	3.6		17.4		30.1
NL		6.0	25.0		2.5	33.5
GB	11.9	4.3		4.6		20.8
Total imports	27.9	28.2	43.9	28.6	15.4	

Without GB-BE cable

	To					Total
From:	FR	BE	DE	NL	GB	exports
2020						
FR		14.5	13.8		16.3	44.6
BE	7.2		4.8	7.6	0.0	19.7
DE	2.6	3.9		14.5		21.1
NL		5.0	3.9		4.3	13.2
GB	5.4	0.0		2.3		7.7
Total imports	15.2	23.4	22.5	24.4	20.6	
2025						
FR		15.2	14.5		11.3	41.0
BE	6.7		5.0	6.7	0.0	18.4
DE	8.3	3.8		17.3		29.3
NL		5.9	25.2		2.5	33.6
GB	10.6	0.0		4.2		14.9
Total imports	25.6	24.9	44.7	28.2	13.9	
2030						
FR		14.3	13.9		10.5	38.6
BE	6.9		5.1	6.6	0.0	18.6
DE	9.1	3.7		17.4		30.1
NL		6.1	24.9		2.5	33.6
GB	12.0	0.0		4.6		16.5
Total imports	28.0	24.0	43.9	28.6	13.1	

Difference (with minus without)						
	To					Total
From:	FR	BE	DE	NL	GB	exports
2020						
FR		0.4	0.0		0.2	0.5
BE	-0.2		**-0.1**	-0.2	4.6	4.2
DE	0.0	**0.1**		0.0		0.1
NL		0.2	-0.1		0.1	0.2
GB	-0.1	1.7		-0.1		1.5
Total imports	-0.3	2.4	-0.2	-0.3	4.8	
2025						
FR		-0.1	0.0		0.1	-0.1
BE	0.0		**0.1**	0.1	2.5	2.7
DE	0.0	**-0.1**		0.0		-0.1
NL		-0.2	0.0		0.0	-0.2
GB	-0.1	3.9		0.0		3.7
Total imports	-0.1	3.5	0.1	0.1	2.5	
2030						
FR		0.0	0.0		0.0	0.0
BE	0.0		**0.0**	0.0	2.4	2.5
DE	0.0	**0.0**		0.0		0.0
NL		-0.1	0.0		0.0	-0.1
GB	-0.1	4.3		0.0		4.2
Total imports	0.0	4.2	0.0	0.1	2.4	

Table 31: *Scenario 3* median baseload prices, €/MWh (2009 money)

	With GB-BE cable			Without GB-BE cable			Difference (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Germany	51.81	54.25	55.90	51.85	54.25	55.90	-0.04	-0.01	0.00
Belgium	51.36	54.63	55.69	51.37	54.85	55.75	-0.01	-0.23	-0.06
France	49.82	51.15	52.65	49.86	51.14	52.61	-0.03	0.01	0.04
Netherlands	52.58	53.89	55.02	52.60	53.88	55.01	-0.02	0.01	0.01
GB	53.82	51.49	50.73	53.75	51.27	50.42	0.07	0.22	0.31
GB minus BE	2.46	-3.14	-4.96	2.38	-3.58	-5.33	0.08	0.44	0.37
BE minus FR	1.54	3.47	3.04	1.51	3.72	3.14	0.02	-0.24	-0.10

Table 32: *Scenario 3* median welfare changes, € million (2009 money)

	Consumer welfare			Producer welfare			Overall welfare		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
BE	2.7	25.0	5.0	28.1	-19.8	-1.0	30.6	5.2	4.1
NL	1.8	-1.6	-2.2	-1.0	2.1	2.6	0.8	0.6	0.5
DE	28.4	3.0	2.3	-28.1	-3.0	-2.2	0.2	0.0	0.0
GB	-32.7	-63.6	-85.7	35.0	75.3	102.2	2.3	11.7	16.6
FR	24.9	-6.6	-20.6	-24.9	7.1	21.4	0.1	0.4	0.7
Total	25.1	-43.8	-101.2	9.2	61.8	123.0	34.1	17.8	21.8

II.5.Scenario 4

Table 33: ***Scenario 4*** **median congestion rents, € million (2009 money)**

	With GB-BE cable			Without GB-BE cable			Change (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
FR to GB	262.4	362.0	480.3	268.1	373.8	494.6	-5.5	-11.6	-14.6
BE to FR	87.0	115.9	162.4	91.3	120.5	167.6	-4.4	-4.6	-5.2
DE to FR	106.0	144.5	185.8	106.2	144.8	186.2	-0.3	-0.4	-0.3
NL to DE	194.4	200.3	220.2	194.4	200.7	221.9	0.0	-0.4	-1.7
NL to BE	53.8	54.7	74.5	58.7	59.9	78.9	-4.9	-5.2	-4.5
NL to GB	64.8	79.8	116.2	68.0	85.9	122.8	-3.2	-6.1	-6.5
DE to BE	47.6	39.6	55.1	49.0	41.5	57.3	-1.4	-1.9	-2.1
GB to BE	57.9	76.5	111.2	0.0	0.0	0.0	**57.9**	**76.5**	**111.2**
Total	873.9	1073.3	1405.7	835.8	1027.2	1329.3	38.1	46.1	76.5

Table 34: ***Scenario 4*** **median TSO revenues, € million (2009 money)**

	With GB-BE cable			Without GB-BE cable			Change (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Unadjusted									
BE	199.6	237.0	332.3	180.1	209.0	287.2	19.4	31.7	48.4
GB	192.6	259.1	353.8	168.1	229.9	308.7	24.6	29.4	45.1
Adjusted									
BE	123.1	143.3	201.6	99.5	111.0	151.9	23.6	32.4	49.7
GB	192.6	259.1	353.8	168.1	229.9	308.7	24.5	29.3	45.1

Table 35: ***Scenario 4*** **median cross-border flows, TWh**

With GB-BE cable

From:	To FR	BE	DE	NL	GB	Total exports
2020						
FR		14.7	13.5		15.0	43.2
BE	7.0		4.7	7.0	4.1	22.7
DE	3.3	4.1		15.1		22.5
NL		5.7	4.5		4.1	14.3
GB	6.8	2.2		2.7		11.6
Total imports	17.0	26.7	22.7	24.7	23.2	
2025						
FR		14.7	14.7		10.9	40.3
BE	6.9		5.7	6.8	2.5	22.0
DE	8.1	3.1		16.5		27.7
NL		5.9	26.1		2.6	34.5
GB	11.5	4.0		4.3		19.8
Total imports	26.5	27.5	46.5	27.7	16.0	
2030						
FR		15.8	14.7		10.2	40.7
BE	6.1		5.2	6.9	2.2	20.4
DE	8.0	3.6		19.3		30.9
NL		5.7	23.4		2.4	31.5
GB	12.8	5.0		5.2		23.0
Total imports	27.0	30.0	43.3	31.4	14.7	

Without GB-BE cable

From:	To FR	BE	DE	NL	GB	Total exports
2020						
FR		14.5	13.5		14.9	42.9
BE	7.1		4.8	7.1	0.0	19.0
DE	3.3	4.0		15.1		22.4
NL		5.5	4.5		4.1	14.1
GB	6.9	0.0		2.7		9.6
Total imports	17.3	24.0	22.8	25.0	19.0	
2025						
FR		14.7	14.7		10.9	40.3
BE	6.9		5.6	6.7	0.0	19.2
DE	8.1	3.1		16.6		27.8
NL		6.1	26.0		2.6	34.7
GB	11.6	0.0		4.3		15.9
Total imports	26.6	23.9	46.4	27.6	13.5	
2030						
FR		15.8	14.7		10.3	40.8
BE	6.0		5.1	6.8	0.0	17.9
DE	8.1	3.7		19.4		31.2
NL		5.9	23.4		2.5	31.8
GB	12.8	0.0		5.1		17.8
Total imports	26.9	25.4	43.1	31.2	12.9	

Difference (with minus without)						
	To					Total
From:	FR	BE	DE	NL	GB	exports
2020						
FR		0.2	0.0		0.1	0.2
BE	-0.1		**-0.1**	-0.2	4.1	3.7
DE	0.0	**0.1**		0.0		0.0
NL		0.2	0.0		0.0	0.2
GB	-0.1	2.2		-0.1		2.1
Total imports	-0.2	2.7	-0.1	-0.3	4.2	
2025						
FR		-0.1	0.0		0.0	0.0
BE	0.0		**0.1**	0.2	2.5	2.8
DE	0.0	**-0.1**		-0.1		-0.1
NL		-0.2	0.1		-0.1	-0.2
GB	-0.1	4.0		0.0		3.8
Total imports	-0.1	3.6	0.2	0.1	2.5	
2030						
FR		0.0	0.1		-0.1	-0.1
BE	0.1		**0.1**	0.2	2.2	2.6
DE	-0.1	**-0.1**		-0.1		-0.3
NL		-0.2	0.1		-0.2	-0.3
GB	0.0	5.0		0.1		5.1
Total imports	0.0	4.7	0.3	0.2	1.9	

Table 36: *Scenario 4* median baseload prices, €/MWh (2009 money)

	With GB-BE cable			Without GB-BE cable			Difference (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Germany	52.05	55.07	56.12	52.06	55.08	56.10	-0.01	-0.01	0.02
Belgium	51.22	53.18	55.42	51.31	53.65	55.67	-0.09	-0.47	-0.24
France	49.41	50.61	51.66	49.38	50.60	51.71	0.02	0.01	-0.04
Netherlands	51.96	53.64	54.99	51.96	53.63	54.99	-0.01	0.01	0.01
GB	52.75	49.68	48.47	52.64	49.39	48.57	0.11	0.29	-0.10
GB minus BE	1.53	-3.51	-6.95	1.33	-4.26	-7.09	0.20	0.75	0.14
BE minus FR	1.82	2.57	3.76	1.93	3.05	3.96	-0.11	-0.48	-0.20

Table 37: *Scenario 4* median welfare changes, € million (2009 money)

	Consumer welfare			Producer welfare			Overall welfare		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
BE	13.4	53.5	23.3	9.8	-28.6	0.7	23.5	25.1	24.5
NL	1.5	-0.5	-0.1	-1.4	1.5	2.5	0.1	1.0	2.5
DE	5.3	2.3	-21.6	-5.1	-1.9	22.2	0.2	0.4	0.7
GB	-36.7	-82.0	65.6	46.0	101.4	-38.3	9.5	19.5	27.1
FR	-10.5	-7.3	22.7	11.3	8.2	-21.7	0.6	1.0	1.0
Total	-27.0	-33.9	89.9	60.6	80.6	-34.6	33.9	47.1	55.8

II.6.Sensitivity 1

Table 38: *Sensitivity 1* median congestion rents, € million (2009 money)

	With GB-BE cable			Without GB-BE cable			Change (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
FR to GB	256.7	363.8	483.7	258.8	375.1	496.6	-2.2	-11.1	-13.1
BE to FR	85.5	141.3	194.8	92.2	146.8	197.0	-6.8	-5.6	-2.2
DE to FR	103.3	148.5	187.3	103.6	148.9	187.4	-0.3	-0.4	-0.2
NL to DE	196.3	216.0	229.7	196.7	216.6	230.5	-0.3	-0.5	-0.9
NL to BE	58.7	83.0	105.2	66.4	88.4	108.7	-7.8	-5.5	-3.4
NL to GB	61.0	82.7	119.5	63.1	88.3	125.3	-2.0	-5.6	-5.9
DE to BE	48.3	61.7	72.0	51.0	64.6	73.2	-2.7	-2.9	-1.2
GB to BE	68.9	94.8	142.0	0.0	0.0	0.0	**68.9**	**94.8**	**142.0**
Total	878.8	1191.8	1534.2	831.8	1128.7	1418.7	46.9	63.1	115.4

Table 39: *Sensitivity 1* median TSO revenues, € million (2009 money)

	With GB-BE cable			Without GB-BE cable			Change (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Unadjusted									
BE	207.4	310.6	418.3	188.0	275.4	353.0	19.3	38.9	67.6
GB	193.3	270.7	372.6	160.9	231.7	311.0	32.3	39.1	61.4
Adjusted									
BE	130.7	190.4	257.0	104.8	149.9	189.5	25.8	40.5	67.6
GB	193.3	270.7	372.6	160.9	231.7	311.0	32.3	39.0	61.6

Table 40: *Sensitivity 1* median cross-border flows, TWh

With GB-BE cable

From:	To FR	BE	DE	NL	GB	Total exports
2020						
FR		14.7	13.0		15.9	43.6
BE	7.1		4.5	6.9	4.5	23.0
DE	3.5	4.2		16.5		24.2
NL		5.8	4.2		4.5	14.5
GB	6.1	2.0		2.3		10.5
Total imports	16.7	26.7	21.8	25.8	24.9	
2025						
FR		15.0	13.7		10.8	39.6
BE	6.6		4.7	6.2	2.4	19.9
DE	9.2	4.1		19.2		32.4
NL		6.5	23.4		2.6	32.5
GB	11.6	4.3		4.3		20.2
Total imports	27.3	29.8	41.9	29.8	15.8	
2030						
FR		16.0	14.5		10.2	40.7
BE	5.8		4.7	6.1	2.3	18.9
DE	8.3	4.1		19.5		31.9
NL		6.5	23.1		2.4	32.0
GB	12.8	5.2		5.2		23.2
Total imports	26.9	31.8	42.2	30.8	14.9	

Without GB-BE cable

From:	To FR	BE	DE	NL	GB	Total exports
2020						
FR		14.4	13.1		15.8	43.3
BE	7.2		4.6	7.1	0.0	18.9
DE	3.5	4.1		16.6		24.2
NL		5.6	4.3		4.4	14.3
GB	6.2	0.0		2.4		8.6
Total imports	16.9	24.2	21.9	26.0	20.2	
2025						
FR		15.1	13.7		10.8	39.6
BE	6.5		4.7	6.1	0.0	17.3
DE	9.1	4.1		19.2		32.5
NL		6.6	23.4		2.6	32.6
GB	11.7	0.0		4.4		16.0
Total imports	27.4	25.8	41.8	29.7	13.4	
2030						
FR		16.0	14.5		10.3	40.8
BE	5.8		4.7	6.1	0.0	16.6
DE	8.3	4.1		19.5		31.9
NL		6.6	23.1		2.6	32.2
GB	12.7	0.0		5.1		17.8
Total imports	26.9	26.6	42.2	30.7	12.9	

Difference (with minus without)						
	To					Total
From:	FR	BE	DE	NL	GB	exports
2020						
FR		0.2	0.0		0.1	0.3
BE	-0.1		**-0.1**	-0.2	4.5	4.1
DE	0.0	**0.1**		0.0		0.1
NL		0.2	0.0		0.0	0.2
GB	-0.1	2.0		-0.1		1.9
Total imports	-0.2	2.5	-0.2	-0.3	4.6	
2025						
FR		-0.1	0.0		0.0	0.0
BE	0.1		**0.0**	0.1	2.4	2.7
DE	0.0	**-0.1**		0.0		-0.1
NL		-0.1	0.1		-0.1	-0.1
GB	-0.1	4.3		0.0		4.2
Total imports	0.0	4.1	0.1	0.1	2.4	
2030						
FR		0.0	0.0		-0.1	-0.1
BE	0.0		**0.0**	0.0	2.3	2.3
DE	0.0	**0.0**		-0.1		-0.1
NL		0.0	0.0		-0.2	-0.2
GB	0.1	5.2		0.1		5.4
Total imports	0.0	5.2	0.0	0.1	2.0	

Table 41: *Sensitivity 1* median baseload prices, €/MWh (2009 money)

	With GB-BE cable			Without GB-BE cable			Difference (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Germany	51.37	54.06	55.80	51.38	54.07	55.78	-0.01	-0.01	0.03
Belgium	50.87	55.07	57.22	50.90	55.32	56.95	-0.04	-0.25	0.27
France	49.22	50.66	51.77	49.19	50.63	51.76	0.03	0.03	0.01
Netherlands	52.08	53.67	55.03	52.08	53.68	54.99	-0.01	-0.01	0.04
GB	53.60	49.61	48.44	53.52	49.29	48.55	0.09	0.32	-0.11
GB minus BE	2.74	-5.46	-8.78	2.61	-6.03	-8.39	0.12	0.57	-0.38
BE minus FR	1.64	4.41	5.45	1.71	4.69	5.18	-0.07	-0.28	0.26

Table 42: *Sensitivity 1* median welfare changes, € million (2009 money)

	Consumer welfare			Producer welfare			Overall welfare		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
BE	2.5	23.5	-36.9	19.1	4.4	50.6	33.1	28.2	13.8
NL	0.0	0.9	-4.9	0.0	-0.1	5.9	0.0	0.9	1.1
DE	8.5	2.8	-18.2	-8.3	-2.3	18.3	0.2	0.3	0.3
GB	-30.0	-92.8	60.0	33.2	111.0	-35.5	2.9	18.1	24.7
FR	-4.5	-19.6	-8.0	5.3	20.7	8.8	0.6	1.0	0.9
Total	-23.5	-85.2	-8.0	49.3	133.5	48.2	36.8	48.4	40.8

II.7.Sensitivity 2

Table 43: *Sensitivity2* median congestion rents, € million (2009 money)

	With GB-BE cable			Without GB-BE cable			Change (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
FR to GB	252.8	360.0	483.5	255.1	371.5	496.6	-2.4	-11.6	-13.3
BE to FR	86.4	133.6	181.0	55.5	135.7	182.6	30.7	-2.1	-1.7
DE to FR	104.7	148.6	180.2	103.6	148.8	180.4	1.1	-0.3	-0.2
NL to DE	195.5	218.8	195.6	179.5	219.0	196.0	15.9	-0.5	-0.4
NL to BE	54.5	66.8	85.8	53.0	68.6	89.3	1.5	-1.9	-3.5
NL to GB	60.6	80.0	119.1	62.6	86.1	124.9	-1.9	-6.1	-5.9
DE to BE	47.1	51.0	68.0	49.1	51.9	69.3	-1.9	-0.9	-1.3
GB to BE	65.7	84.4	125.1	0.0	0.0	0.0	**65.7**	**84.4**	**125.1**
Total	867.3	1143.1	1438.2	758.4	1081.6	1339.2	108.9	61.5	99.1

Table 44: *Sensitivity 2* median TSO revenues, € million (2009 money)

	With GB-BE cable			Without GB-BE cable			Change (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Unadjusted									
BE	203.1	277.7	377.5	135.3	239.8	320.2	67.6	39.2	59.7
GB	189.6	262.2	363.8	158.9	228.8	310.7	30.6	33.3	52.9
Adjusted									
BE	126.9	167.9	229.9	78.8	128.1	170.6	48.1	39.8	59.3
GB	189.6	262.2	363.8	158.9	228.8	310.7	30.7	33.4	53.1

Table 45: *Sensitivity 2* median cross-border flows, TWh

With GB-BE cable

From:	To: FR	BE	DE	NL	GB	Total exports
2020						
FR		16.0	14.0		15.8	45.8
BE	5.9		4.3	8.8	4.5	23.5
DE	3.3	4.4		15.4		23.1
NL		4.6	4.5		4.5	13.6
GB	6.2	2.0		2.3		10.5
Total imports	15.4	27.0	22.8	26.5	24.8	
2025						
FR		16.2	14.7		10.6	41.5
BE	5.7		4.6	8.1	2.3	20.8
DE	8.5	4.1		18.2		30.9
NL		4.9	25.0		2.6	32.5
GB	11.7	4.2		4.3		20.2
Total imports	25.9	29.4	44.4	30.6	15.6	
2030						
FR		17.3	15.0		10.2	42.6
BE	5.0		4.3	7.8	2.3	19.3
DE	8.3	4.5		21.0		33.8
NL		4.9	21.8		2.5	29.2
GB	12.9	5.1		5.0		23.0
Total imports	26.1	31.8	41.1	33.9	15.0	

Without GB-BE cable

From:	To: FR	BE	DE	NL	GB	Total exports
2020						
FR		8.0	14.0		15.6	37.6
BE	3.4		4.4	5.2	0.0	13.0
DE	3.0	4.4		11.9		19.3
NL		4.4	4.5		4.5	13.4
GB	6.4	0.0		2.3		8.7
Total imports	12.7	16.8	23.0	19.4	20.1	
2025						
FR		16.2	14.7		10.6	41.5
BE	5.6		4.6	8.0	0.0	18.2
DE	8.5	4.2		18.2		30.9
NL		5.0	25.0		2.7	32.6
GB	11.9	0.0		4.3		16.2
Total imports	26.0	25.4	44.3	30.6	13.2	
2030						
FR		17.3	15.0		10.4	42.6
BE	5.0		4.3	7.9	0.0	17.2
DE	8.3	4.5		21.1		33.9
NL		4.9	21.7		2.7	29.2
GB	12.8	0.0		5.0		17.8
Total imports	26.1	26.6	41.0	33.9	13.0	

Difference (with minus without)						
	To					Total
From:	FR	BE	DE	NL	GB	exports
2020						
FR		8.0	0.0		0.1	8.1
BE	2.6		**-0.1**	3.6	4.5	10.5
DE	0.2	**0.1**		3.5		3.9
NL		0.2	0.0		0.1	0.2
GB	-0.1	2.0		-0.1		1.8
Total imports	2.7	10.3	-0.1	7.0	4.7	
2025						
FR		-0.1	0.0		0.1	0.0
BE	0.0		**0.0**	0.1	2.3	2.5
DE	0.0	**0.0**		0.0		-0.1
NL		-0.1	0.1		-0.1	-0.1
GB	-0.1	4.2		0.0		4.1
Total imports	-0.1	4.0	0.1	0.1	2.3	
2030						
FR		0.0	0.0		-0.1	-0.1
BE	0.0		**0.0**	-0.1	2.3	2.2
DE	0.0	**0.0**		-0.1		-0.1
NL		0.0	0.1		-0.2	0.0
GB	0.0	5.1		0.1		5.2
Total imports	0.0	5.2	0.1	-0.1	2.0	

Table 46: *Sensitivity 2* median baseload prices, €/MWh (2009 money)

	With GB-BE cable			Without GB-BE cable			Difference (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Germany	51.40	53.94	54.90	51.42	53.94	54.89	-0.02	0.00	0.01
Belgium	51.46	54.62	56.35	51.60	54.74	56.17	-0.14	-0.12	0.18
France	49.75	51.17	52.29	49.75	51.12	52.28	0.00	0.05	0.02
Netherlands	52.05	53.59	54.57	52.05	53.57	54.56	0.00	0.02	0.01
GB	53.78	49.85	48.41	53.68	49.46	48.47	0.09	0.39	-0.06
GB minus BE	2.32	-4.77	-7.94	2.08	-5.28	-7.70	0.24	0.51	-0.24
BE minus FR	1.71	3.45	4.06	1.85	3.63	3.89	-0.14	-0.17	0.17

Table 47: *Sensitivity 2* median welfare changes, € million (2009 money)

	Consumer welfare			Producer welfare			Overall welfare		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
BE	18.5	10.5	-24.3	10.8	0.4	37.0	29.6	10.9	12.7
NL	-0.6	-3.9	-2.2	1.0	4.8	3.0	0.5	1.0	0.7
DE	15.7	-4.6	-10.1	-15.6	4.7	10.3	0.2	0.1	0.2
GB	-35.5	-107.3	43.8	38.5	127.0	-18.3	3.1	19.3	25.1
FR	3.7	-31.3	-11.6	-3.3	32.4	12.6	0.3	1.1	1.0
Total	1.7	-136.5	-4.4	31.4	169.4	44.6	33.7	32.5	39.7

II.8.Sensitivity 3

Table 48: *Sensitivity 3* median congestion rents, € million (2009 money)

	With GB-BE cable			Without GB-BE cable			Change (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
FR to GB	334.3	429.8	571.8	331.5	442.4	585.6	-2.4	-13.1	-14.2
BE to FR	106.4	135.8	189.3	111.6	136.8	189.9	-4.7	-0.9	-0.6
DE to FR	117.8	150.8	199.0	118.2	151.1	199.1	-0.2	-0.2	-0.1
NL to DE	131.4	142.8	163.8	130.1	142.7	164.9	0.6	0.0	-1.2
NL to BE	44.5	52.2	67.9	50.2	55.3	69.5	-6.0	-3.1	-1.6
NL to GB	62.6	82.5	119.2	64.6	89.2	126.1	-2.2	-6.8	-6.9
DE to BE	38.8	38.3	53.2	41.1	39.4	54.0	-2.1	-1.1	-0.8
GB to BE	63.5	81.5	127.2	0.0	0.0	0.0	**63.5**	**81.5**	**127.2**
Total	899.3	1113.7	1491.3	847.3	1057.0	1389.1	52.0	56.7	102.2

Table 49: *Sensitivity 3* median TSO revenues, € million (2009 money)

	With GB-BE cable			Without GB-BE cable			Change (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Unadjusted									
BE	211.9	259.5	364.9	191.7	222.9	303.7	20.5	39.0	62.5
GB	230.2	296.9	409.1	198.0	265.8	355.9	29.2	30.8	53.0
Adjusted									
BE	126.6	153.9	218.8	101.5	115.8	156.7	25.1	38.1	62.1
GB	230.2	296.9	409.1	198.0	265.8	355.9	32.2	31.1	53.2

Table 50: *Sensitivity 3* median cross-border flows, TWh

With GB-BE cable

From:	To FR	BE	DE	NL	GB	Total exports
2020						
FR		14.3	13.0		15.6	43.0
BE	7.1		4.6	6.7	4.4	22.9
DE	4.0	4.1		15.5		23.7
NL		6.0	4.1		4.5	14.5
GB	6.9	2.1		2.4		11.5
Total imports	18.1	26.6	21.7	24.6	24.5	
2025						
FR		14.2	13.1		10.6	37.9
BE	7.1		4.9	6.2	2.4	20.6
DE	9.8	3.9		18.1		31.8
NL		6.5	24.2		2.6	33.3
GB	12.0	4.2		4.3		20.4
Total imports	28.9	28.7	42.2	28.6	15.6	
2030						
FR		15.0	13.7		9.9	38.6
BE	6.5		4.8	6.2	2.3	19.7
DE	9.1	4.0		19.0		32.0
NL		6.5	23.4		2.4	32.3
GB	13.2	5.0		5.1		23.3
Total imports	28.8	30.4	41.9	30.2	14.6	

Without GB-BE cable

From:	To FR	BE	DE	NL	GB	Total exports
2020						
FR		14.2	13.1		15.6	42.8
BE	7.2		4.7	6.9	0.0	18.8
DE	4.0	4.1		15.6		23.7
NL		5.8	4.1		4.4	14.3
GB	7.0	0.0		2.4		9.4
Total imports	18.2	24.0	21.8	24.9	20.0	
2025						
FR		14.3	13.2		10.5	37.9
BE	7.1		4.8	6.1	0.0	18.0
DE	9.8	4.0		18.1		31.9
NL		6.6	24.1		2.7	33.4
GB	12.1	0.0		4.3		16.4
Total imports	29.0	24.8	42.1	28.6	13.2	
2030						
FR		14.9	13.7		10.1	38.6
BE	6.5		4.8	6.2	0.0	17.6
DE	9.2	3.9		19.0		32.1
NL		6.4	23.3		2.6	32.3
GB	13.1	0.0		5.0		18.1
Total imports	28.8	25.2	41.8	30.2	12.7	

Difference (with minus without)						
	To					Total
From:	FR	BE	DE	NL	GB	exports
2020						
FR		0.2	-0.1		0.0	0.1
BE	-0.1		**0.0**	-0.2	4.4	4.1
DE	0.0	**0.0**		-0.1		0.0
NL		0.2	0.0		0.1	0.3
GB	0.0	2.1		-0.1		2.0
Total imports	-0.1	2.5	-0.1	-0.3	4.5	
2025						
FR		-0.1	0.0		0.1	0.0
BE	0.0		**0.0**	0.1	2.4	2.6
DE	0.0	**-0.1**		0.0		-0.1
NL		-0.1	0.0		0.0	-0.1
GB	-0.1	4.2		0.0		4.0
Total imports	-0.1	3.9	0.1	0.1	2.4	
2030						
FR		0.1	0.1		-0.2	0.0
BE	0.0		**-0.1**	0.0	2.3	2.2
DE	-0.1	**0.1**		-0.1		-0.1
NL		0.0	0.1		-0.2	-0.1
GB	0.1	5.0		0.1		5.2
Total imports	0.0	5.2	0.1	0.0	2.0	

Table 51: *Sensitivity 3* median baseload prices, €/MWh (2009 money)

	With GB-BE cable			Without GB-BE cable			Difference (with minus without)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Germany	51.73	54.07	55.64	51.75	54.07	55.63	-0.02	0.00	0.01
Belgium	52.08	54.53	56.01	52.32	54.84	55.83	-0.24	-0.31	0.18
France	51.34	53.19	54.95	51.18	53.12	54.98	0.16	0.07	-0.03
Netherlands	52.66	53.88	54.87	52.69	53.88	54.84	-0.02	0.00	0.04
GB	53.76	49.77	48.41	53.72	49.37	48.57	0.05	0.41	-0.16
GB minus BE	1.69	-4.76	-7.60	1.40	-5.47	-7.26	0.29	0.71	-0.34
BE minus FR	0.74	1.34	1.07	1.14	1.72	0.85	-0.40	-0.38	0.21

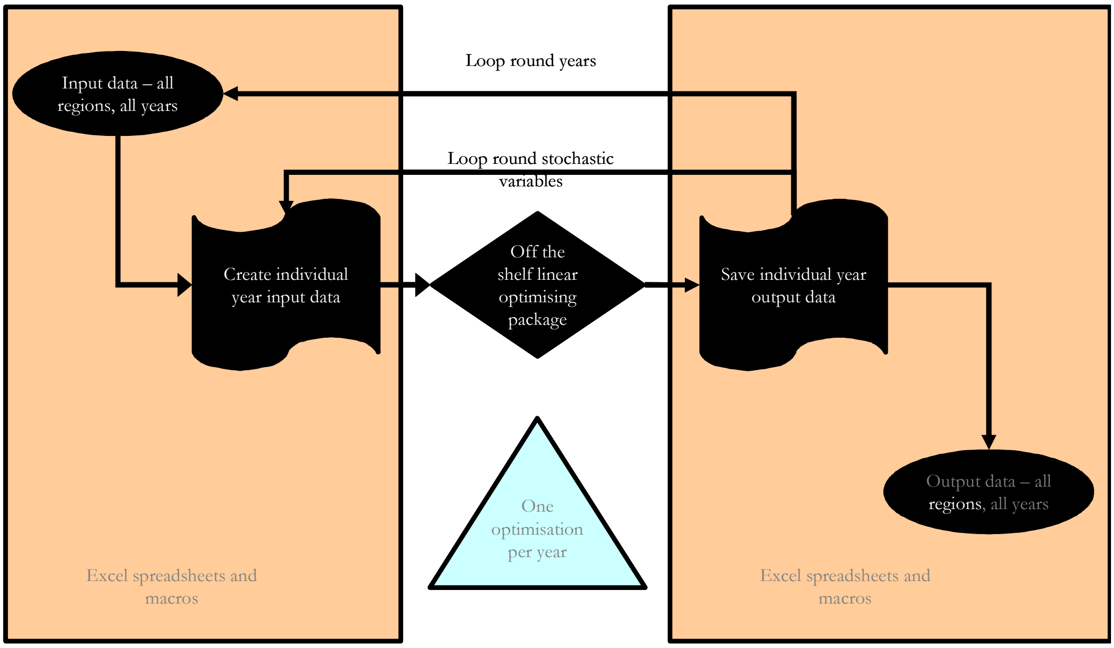
Table 52: *Sensitivity 3* median welfare changes, € million (2009 money)

	Consumer welfare			Producer welfare			Overall welfare		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
BE	33.4	34.9	-23.1	-7.5	-25.6	30.2	25.2	9.5	7.1
NL	4.5	-0.4	-6.0	-5.0	0.9	7.6	-0.6	0.6	1.6
DE	12.4	-1.7	-8.4	-12.2	1.9	8.6	0.2	0.2	0.2
GB	-28.2	-120.4	86.4	31.0	142.3	-58.8	3.1	22.0	27.8
FR	-15.4	-48.8	31.1	15.9	50.0	-30.0	0.5	1.0	0.7
Total	6.7	-136.3	80.1	22.3	169.7	-42.5	28.4	33.4	37.5

Appendix III Details of the BAM model

At the heart of BAM is a cost-minimising plant scheduler that, in conjunction with a sophisticated fixed-cost recovery module, enables marginal costs and prices for any number of interconnected countries (or regions) to be modelled. The model can be run in two modes: (a) fast – deterministic runs with simplified approaches to forced outages, to demand variations and to wind output patterns to provide initial indications of prices or to model longer periods and (b) detailed – stochastic representation of these variables using a random number generator to give a more detailed insight into prices and their volatility but taking longer to run. This is illustrated in Figure 43.

Figure 43: Outline of model structure



Model inputs

The generic types of required input data include

- Fuel prices: generic international prices for coal and oil products and country specific domestic fuel prices,[26] and taxes;
- Fuel characteristics: calorific values, carbon, sulphur and nitrogen content;
- Current plant capacities, retirement of existing plant and entry of new capacity, including renewables;

[26] In addition to allowing gas contract prices to be linked to other fuel prices and inflation, it will be possible to include indexation to the previous year's electricity prices.

• Other plant characteristics (fuel blending requirements, maintenance requirements, environmental measures e.g. flue gas desulphurisation levels, forced outage levels, thermal efficiency etc.);

• Plant costs: fuel transport costs, non-fuel variable costs (e.g. coal milling costs, variable O&M costs, market power uplifts etc.), fixed costs; transmission loss factors;

• Electricity demand profiles and growth;

• Contractual arrangements (physical bilateral contracts, must-take fuel contracts);

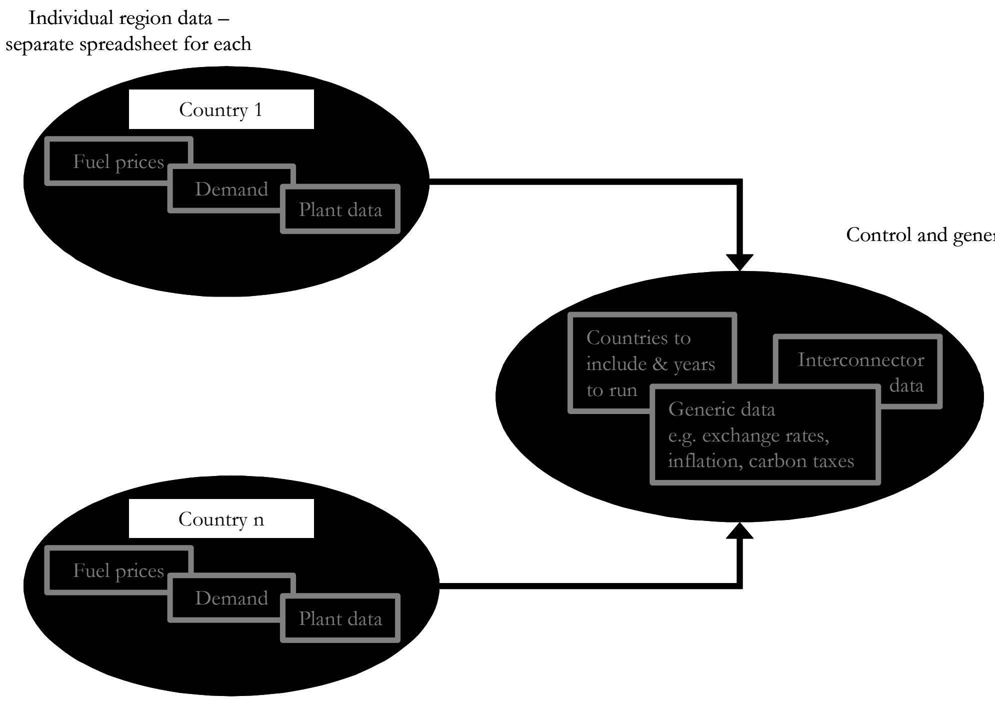
• Environmental constraints and costs: plant and country/regional emissions limits and costs,

• Financial parameters: exchange rates and inflation rates;

• Inter-regional data: monthly capacities in both directions, losses etc;

These data are required for each country (or region within a country where market splitting occurs) to be included within the model. The model can accommodate varying numbers of countries, with all the data specific to a particular country grouped into an individual Excel spreadsheet. Generic and control data are held in a separate spreadsheet, as shown in Figure 44.

Figure 44: Data structure



The model utilises a characteristic day representation of demand with 3 characteristic days for each month (weekday, Saturday, Sunday) being used to represent the demand over a year. Since the countries modelled will have electrical connections to other countries, it is important to incorporate the impact of flows into and out of the model area. The model can incorporate historical net flows from each surrounding country as zero-priced flows, which effectively forces these to take place, using TSO data. However, the model structure allows any number of import and export flows to be incorporated (with separate volumes and prices for each flow for each month and distinguished between day and night). Thus, a simplified step-wise approximation to the marginal cost curve in a country can be used to define several tranches of import (or export) flows. Whilst this method is more flexible, it effectively requires modelling the surrounding countries (at least to some extent) in order to produce an appropriate marginal cost curve. Accordingly, we only use the more complex 'marginal cost curve' approach to model power flows to and from NordPool, because historically flows to and from this region tend to be more price sensitive. All other external flows are represented using historical flow data provided by TSOs.

Outputs other than prices

In addition to detailed price data, the model also produces information on the output, revenues and costs of each generating plant, the flows across interconnectors (both within the model area and to countries outside it), fuel consumption and emissions levels.

III.1. Optimisation steps and fixed and capital cost recovery

The initial in BAM optimisation is carried out based solely on short-run marginal costs. In other words, the cost of generation for plant p in country c is, for month m, day d and hour h:

$$Cost(c,p,s,d,h,1) = \{FC(c,s,p) + VC(c,p) + CC(c,p,s)\} \times Output(c,p,s,d,h,1)$$

Where FC = fuel cost, VC = variable cost (including variable fuel delivery costs) and CC = carbon cost.

The internal transfers between the countries being modelled are determined from a set of inter-related constraints.

The first relates to energy conservation: the demand in a country c must be met by the output of plant in that country, imports from other countries (cc) (*Flow(cc,c,d,s,h)*) and generation from pumped storage plants minus any exports from that country (*Flow(c,cc,d,s,h)*) and any pumped storage pumping:

$$\begin{aligned} Demand(c,s,d,h) = {} & \sum_p Output(c,p,s,d,h) + \sum_{cc} (1 - Loss(cc,c)) \times Flow(cc,c,d,s,h) + \sum_z PSGen(c,z,s,d,h) \\ & - \sum_{cc} Flow(c,cc,d,s,h) - \sum_z PSPump(c,z,s,d,h) \end{aligned}$$

The second limits the flows across the interconnectors to the capacity of the interconnector for that month. Finally, the costs of the region being modelled are the sum of the costs of all the plants operating plus any interconnector charges that apply. The cumulative effect of these constraints is to direct flows between countries so as to minimise overall costs.

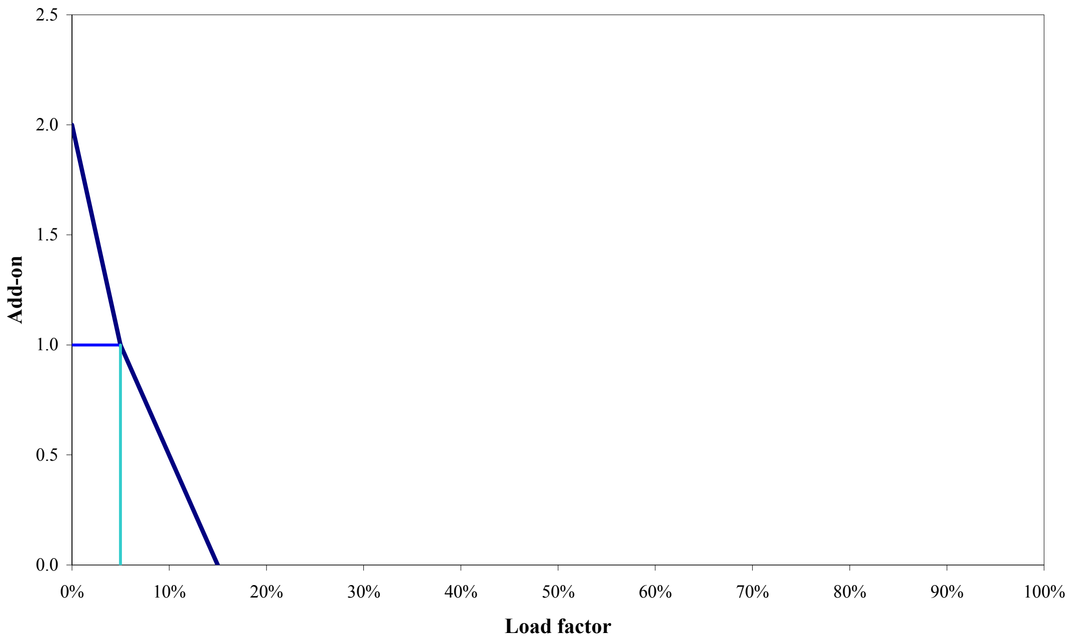
The fixed cost recovery for each country is determined from the resulting marginal costs and results in the calculation of a fixed cost add-on for each hour – *FAO(c,s,d,h).* These are determined from the additional revenues required to meet the specified costs of a typical peaking, mid-merit or baseload plant.

The specified costs are determined from:

- Marginal costs of the chosen typical plant (which depend on assumptions on efficiency, fuel used, variable operating costs, and carbon costs);
- Fixed cost recovery allowance (which depend on assumptions on the percentage of fixed costs that can be recovered, the underlying fixed costs for the chosen technology and the fixed fuel delivery costs *i.e.* capacity charges);
- Capital cost recovery allowance (which depends on assumptions on the percentage of capital costs that can be recovered and the underlying capital costs for the chosen technology).

If the required revenues (costs –degradation adjusted[27] SMC revenues) are highest for a peaking plant, then the add-ons are determined solely from these required revenues. Add-ons are only calculated for the peak hours e.g. the top 15% of hours sorted by domestic demand, and outside of these prices remain at SMC levels. This is illustrated in the diagram below.

Figure 45: Fixed cost recovery based on a peaking plant's requirements



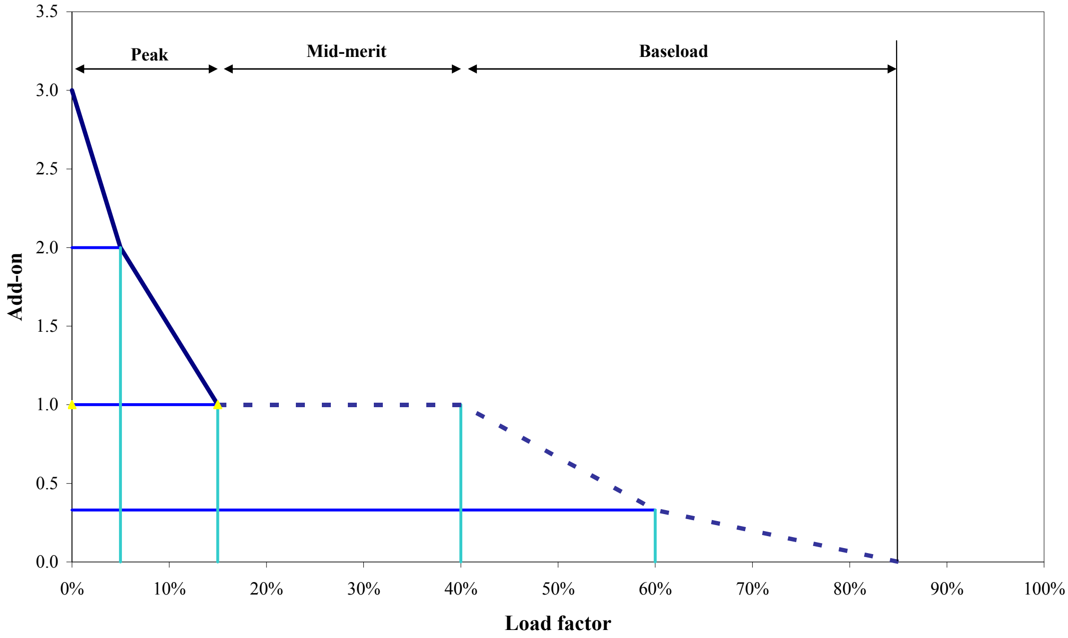
The shape of the fixed cost add-ons depends on the assumptions that are made regarding (i) the overall load factor for peaking plant - 15% in this example, (ii) the load factor at which the slope of the add-ons can change - 5% in the example and (iii) the relative scale of the add-ons at the absolute peak and the intermediate break point – 2:1 in the example.

1. If the required revenues are highest for a baseload plant, then the add-ons are determined on this basis. The shape of the fixed cost add-ons is, however, adjusted to ensure that the peaking

[27] The degradation is included to capture the fact that, for example, a peaking plant is very unlikely only to operate in precisely the highest demand hours but will typically operate in a few slightly lower hours due to uncertainty about demand and plant dynamics.

plant is also able to recover its costs, which may mean that proportionally the most fixed cost recovery still takes place in peak hours.

Figure 46: Fixed cost recovery based on a baseload plant's requirements



The shape of the fixed cost add-ons is fixed for the peak region (and its area has to equal the required revenue for the peak plant) but the relative height of the mid-merit add-on (shown as 1 at 40% in the example) and the intermediate point in the baseload region (shown as 0.33 at 60% in the example) can be altered. This is to ensure that the peak plant recovers its costs and that the baseload plant does not over-recover its costs. However, the relationship between the mid-merit point and the intermediate baseload point (1:0.33) is preserved e.g. it might change to 0.5:0.165 but not 0.5:0.1. Thus, the only additional assumptions to those regarding the peak segment that are relied up are (i) the load factors for the mid-merit and baseload plant and the intermediate point in the baseload region and (ii) the relative cost recovery at the mid-merit load factor and the intermediate baseload load factor.

If the mid-merit plant had the highest required revenues, then this would determine the add-ons but in general we assume that no new mid-merit plant will be built and so do not include capital costs in the specified costs.

Values for the various degrees of freedom associated with the fixed cost recovery mechanism (percentage of allowed fixed cost recovery, percentage of allowed capital cost recovery, load factors – including peak and baseload intermediate points – and relative cost recoveries) are all determined from backcasts (and also to some extent from previous studies where we have sought to replicate the forward curves for electricity prices).

The only other degree of freedom in terms of shaping prices is the off-peak reduction in prices to reflect a desire to avoid incurring start-up costs over-night. We have deduced these values on a monthly basis from the back-cast and then for future years we assume that they vary in line with changes in the costs of Natural Gas i.e. generators still seek to avoid start-up costs but the level of start-up costs varies with fuel costs.

The prices for a particular hour at the end of the first iteration are the marginal costs for that country from the optimisation (strictly, the dual values of the optimisation) plus the fixed cost add-on for that hour and country.

The second optimisation is carried out including the fixed cost add-on for a country in the costs of all the plants in that country.

$$Cost(c,p,s,d,h,2) = \{FC(c,s,p) + VC(c,p) + CC(c,p,s) + FAO(c,s,d,h)\} \times Output(c,p,s,d,h,2)$$

The internal transfers between the countries being modelled are again determined by the cost of the marginal plant in each country but in this case the marginal costs include the fixed cost add-on for that country. Consequently although FC, VC and CC for the marginal plant could be the same in two countries, if FAO is different for the two counties, there could be a transfer between them.

The prices for a particular hour at the end of the second iteration are the dual values of the optimisation, which in this case already include the fixed cost add-ons. Consequently, no further adjustments for fixed cost recovery are made.

III.2. Reduction of off-peak prices

Many generators are prepared to offer prices below their marginal costs overnight in order to avoid having to close down and re-start their plants. Hence, the overnight price may often be set, not by the plant with the lowest marginal cost, but by the plant that is most keen to avoid an overnight shut-down and the subsequent start up costs (and/or plants with strict ramping requirements the following morning). Thus, the assumption that the price is set by the plant with the lowest marginal cost does not always hold overnight, because it is the willingness to avoid start-up costs that sets the price. To mimic this effect in BAM, we include negative market power offsets during the overnight periods.

To determine how large these offsets should be, we have relied primarily upon the backcasting exercise, described in Appendix IV. However, we have also checked that the values at which we arrive are broadly consistent with what we consider the start-up costs for marginal plant might have been, taking into account our assumptions on fuel prices.

The question then arises as to how these offsets should be projected forward from the backcast to the years that we model. Our assumption is that the offsets should move in line with our changing fuel price assumptions so that, for example, if the offset in one country in January 2005 was 10 €/MWh when the gas price was 2 €/MMBtu and our assumed gas price for January 2015 was 1.5 €/MMBtu then the offset for that country in January 2015 would be 7.5 €/MWh (=10x1.5/2).

The implicit assumption underlying this approach is that the start-up costs of the marginal plants, in terms of the type and quantity of fuel required for a start-up, will not change over time. In these circumstances, the start-up costs will simply vary in line with changing fuel prices. Of course, it can be argued that over time different plants will be at the margin so that our assumption may not be fully justified. However, given the context of what we are trying to model, we believe that this simplification is unlikely to distort the results materially and is more appropriate than the only other simple approach – simply keeping the start-up cost adjustments constant.

Appendix IV : Backcasting exercise

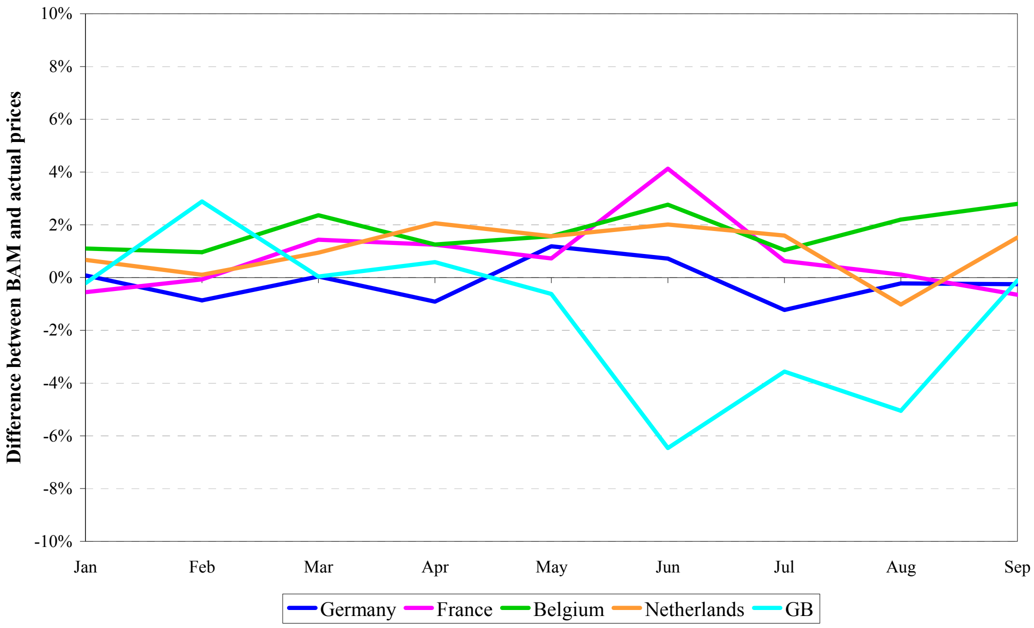
To gain confidence in BAM's projections of prices and interconnector revenues, a 'backcasting' exercise was carried out. The 2009 electricity markets were modelled and compared to actual prices for the first part of the year (up to either June or September depending on the actual data we were able to obtain), using the relevant fuel prices. We imposed the actual pattern of hydro, wind, solar and nuclear output for each country[28] but left the model free to schedule fossil fired plants and determine cross-border flows and prices.

5.5 Absolute price levels and seasonal price profiles

Figure 47 shows the difference between actual monthly average baseload prices from the deterministic backcast and those estimated by BAM for all the countries modelled. It shows that for all the months where we had actual data, the difference between the BAM estimates and the actual prices was less than 10% in absolute terms.

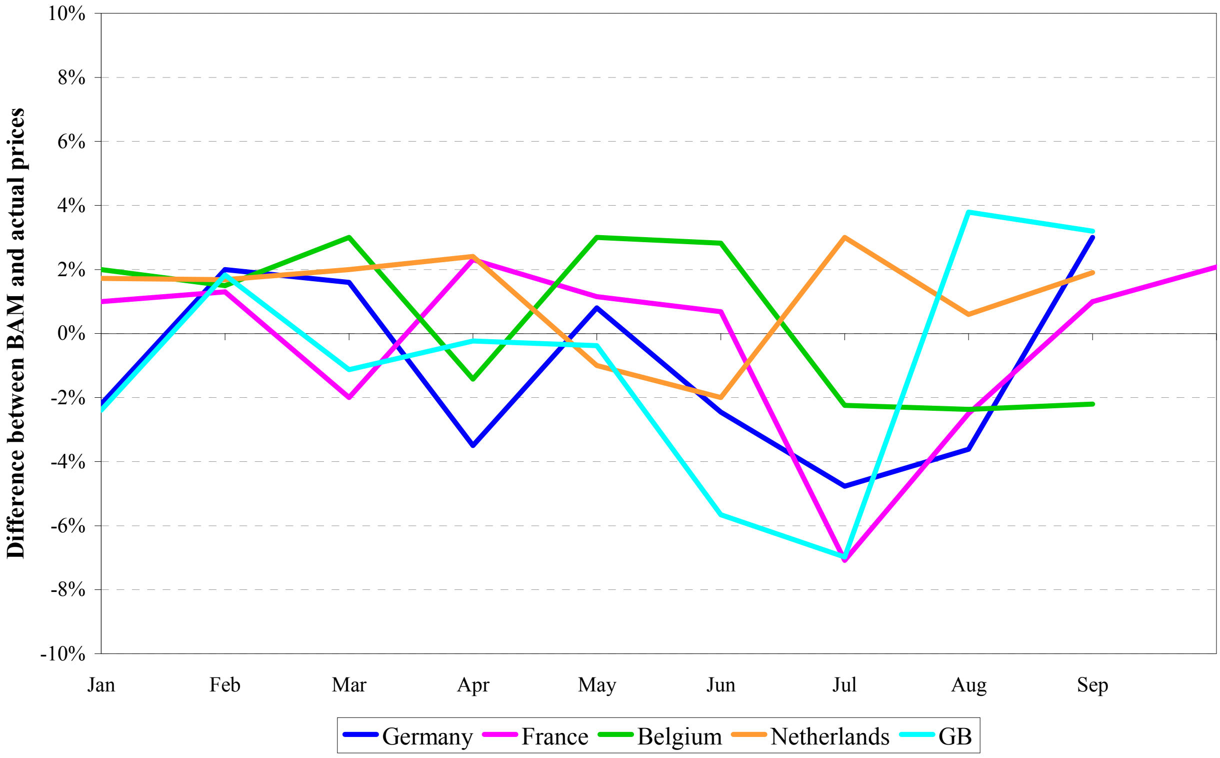
The under-estimate by BAM of GB prices in May and June is driven by the fact that actual GB electricity prices rose in these months even though fuel prices and demand fell. It is not obvious why electricity prices rose, given that fuel prices, particularly gas prices, continued to decline. Since we have no data on the availability of GB plants (nor their output), it may be that the discrepancy is due to actual plant outages exceeding those assumed by BAM.

Figure 47: Monthly baseload prices – deterministic BAM versus actual



[28] We obtained this data from a variety of sources, notably ENTSO-e, EEX, RTE and Elia.

Figure 48: Monthly baseload prices – probabilistic BAM versus actual



IV.1. Daily price patterns

Figure 49 to Figure 52 below compare actual and deterministic average summer prices (April to September except for the Netherlands which is April to June[29]) and winter prices (January to March) over the day in 2009 for all the countries modelled except GB.[30] As can be seen, there is good agreement in all cases.

[29] We do not currently have access to hourly prices beyond June for the Netherlands.

[30] We only have access to peak and baseload prices, not hourly prices and so are unable to carry out a daily comparison.

Figure 49: BAM deterministic backcast prices plotted against historical prices - Belgium

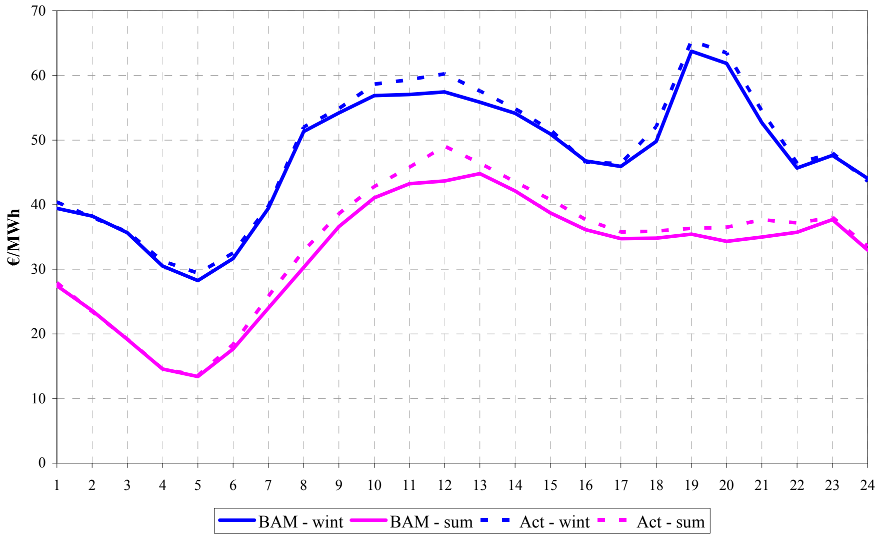


Figure 50: BAM deterministic backcast prices plotted against historical prices- Germany

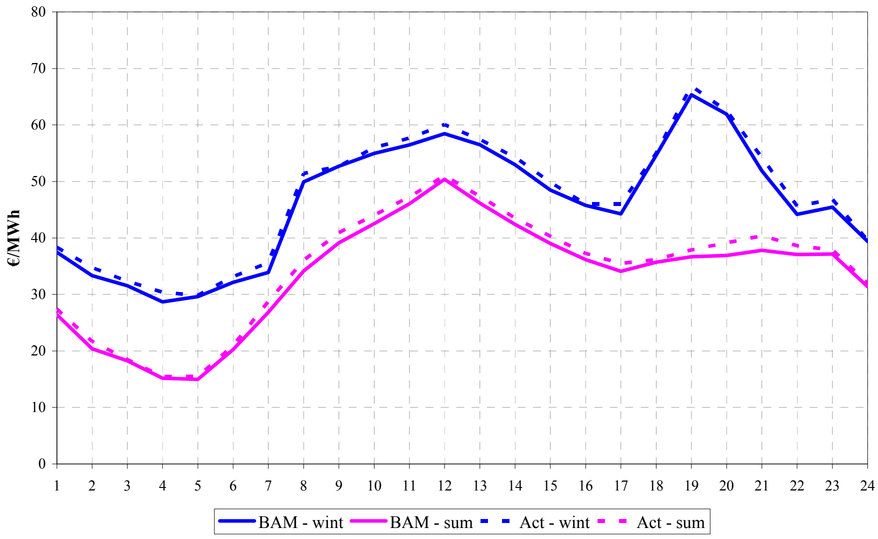


Figure 51: BAM deterministic backcast prices plotted against historical prices – France

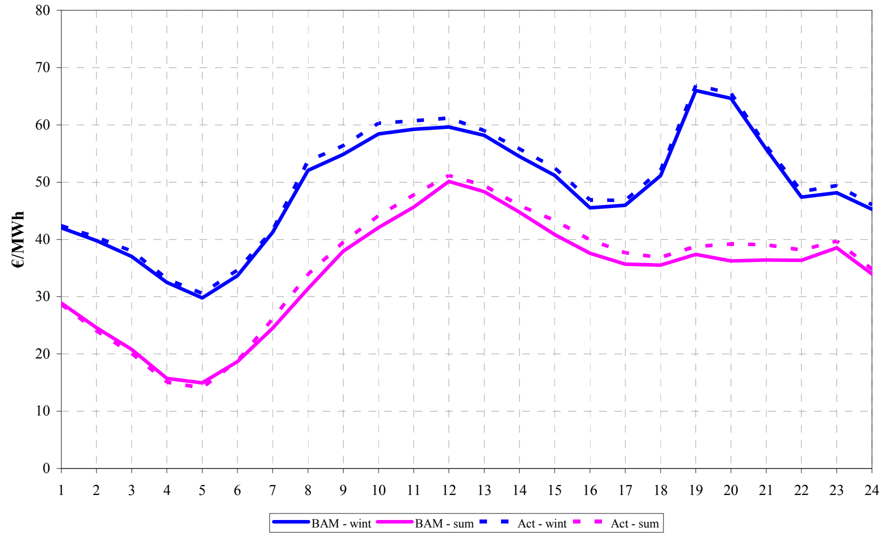
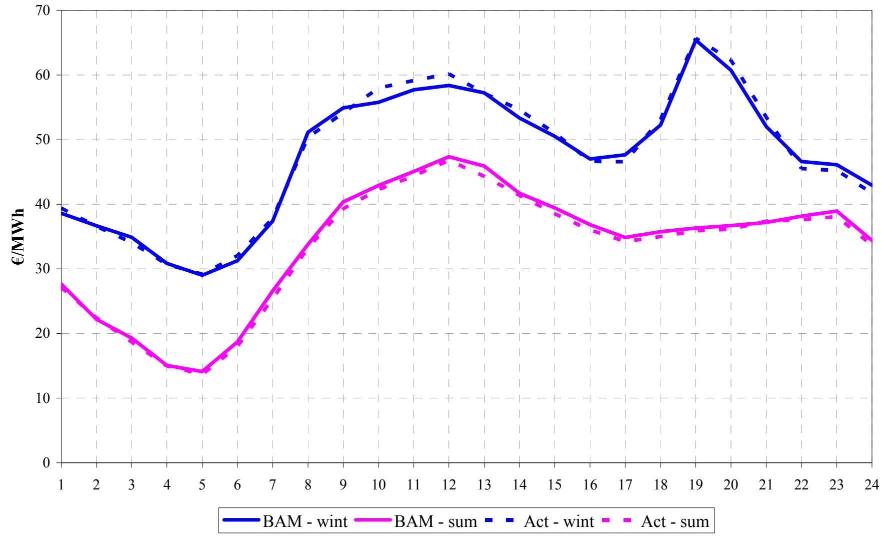


Figure 52: BAM deterministic backcast prices plotted against historical prices – Netherlands



5.6 Congestion revenues

For the backcast, we fixed the volumes of flows between NordPool and Germany and the Netherlands. We did this because of the effect that hydrological conditions have on these flows: our normal methodology for modeling these flows is effectively to assume average weather conditions, which is appropriate for long term forecasting but not for backcasting.

Figure 53 and Figure 54 show the congestion revenues estimated from the deterministic BAM backcast compared to a calculation of actual revenues based on historic price differences and commercial cross-border flows. Table 53 compares the annual results under both the deterministic and probabilistic backcasts.

Figure 53: Deterministic congestion revenues – Jan to Mar

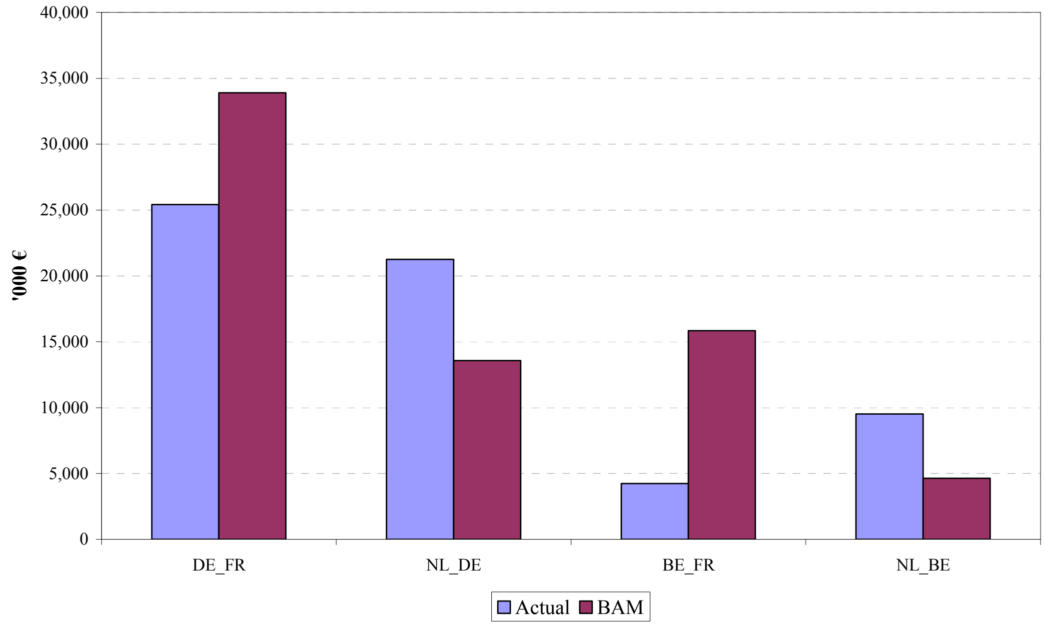


Figure 54: Deterministic congestion revenues – Apr - Jun

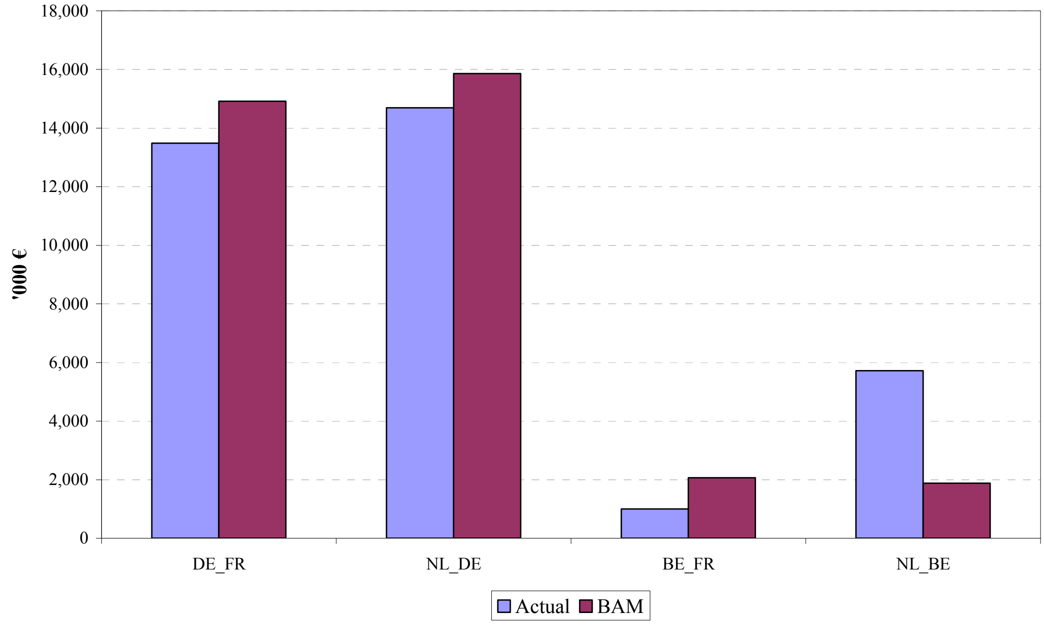


Table 53 shows the estimated congestion rents vs. the BAM deterministic and probabilistic congestion rents. By estimated rents, we mean the congestion rents that would have occurred had 100% of the NTC value of the interconnector been used for market coupling. We estimate the congestion rents in these cases from outturn market prices.

Table 53: 2009 congestion revenue backcasts, € million

		Estimated	BAM	
			Det	Prob
GB	France		63.3	106.6
France	Belgium	31.3	36.1	88.4
France	Germany	141.0	104.6	246.2
Germany	Netherlands	73.98	61.3	78.4
Belgium	Netherlands	33.4	27.1	58.8

Since performing the back casting exercise and creating the table above, we gained access to day-ahead GB prices from 2009. Therefore we were able to estimate the "actual" congestion revenues that would have been earned on the GB-France interconnector (calculated as the difference in day-ahead prices, allowing for BSUoS and losses, multiplied by the commercial cross-border flows) for comparison with the BAM results. In contrast to the continental interconnectors, we find that BAM tends to under-estimate the congestion revenues on the GB-France interconnector, although the probabilistic backcast was within 10% of the estimated actual revenues. Because the model seems to predict the revenues of interconnectors from GB quit accurately, we do not make any downward adjustment to predicted GB interconnector revenues, including Nemo.

IV.2. Prices vs. demand

For each country modelled (except GB), we show the natural log (ln) of BAM prices and the log of actual prices, both plotted against the corresponding demand. We do separate plots for summer and winter, because the relationship between prices and demand varies by season. We have not made a similar plot for GB, because we do not have hourly outturn prices available for GB.

In most cases the slopes of the Bam prices and the actual prices seem to match well. Note that for Germany in particular, the BAM demand has been increased to reflect the project sponsors view of 2009 demand and distributed generation. Moreover, we only had winter outturn prices for the January to march period, whereas BAM also simulated the October to December period when demand was higher. Hence the Bam price points have been shifted to the right relative to the outturn German prices, and there are more BAM points at times of high demand because of the simulation of the October-December period.

Figure 55: Natural log of actual 2009 winter prices for Germany and natural log of BAM 2009 winter prices for Germany plotted against corresponding German demand

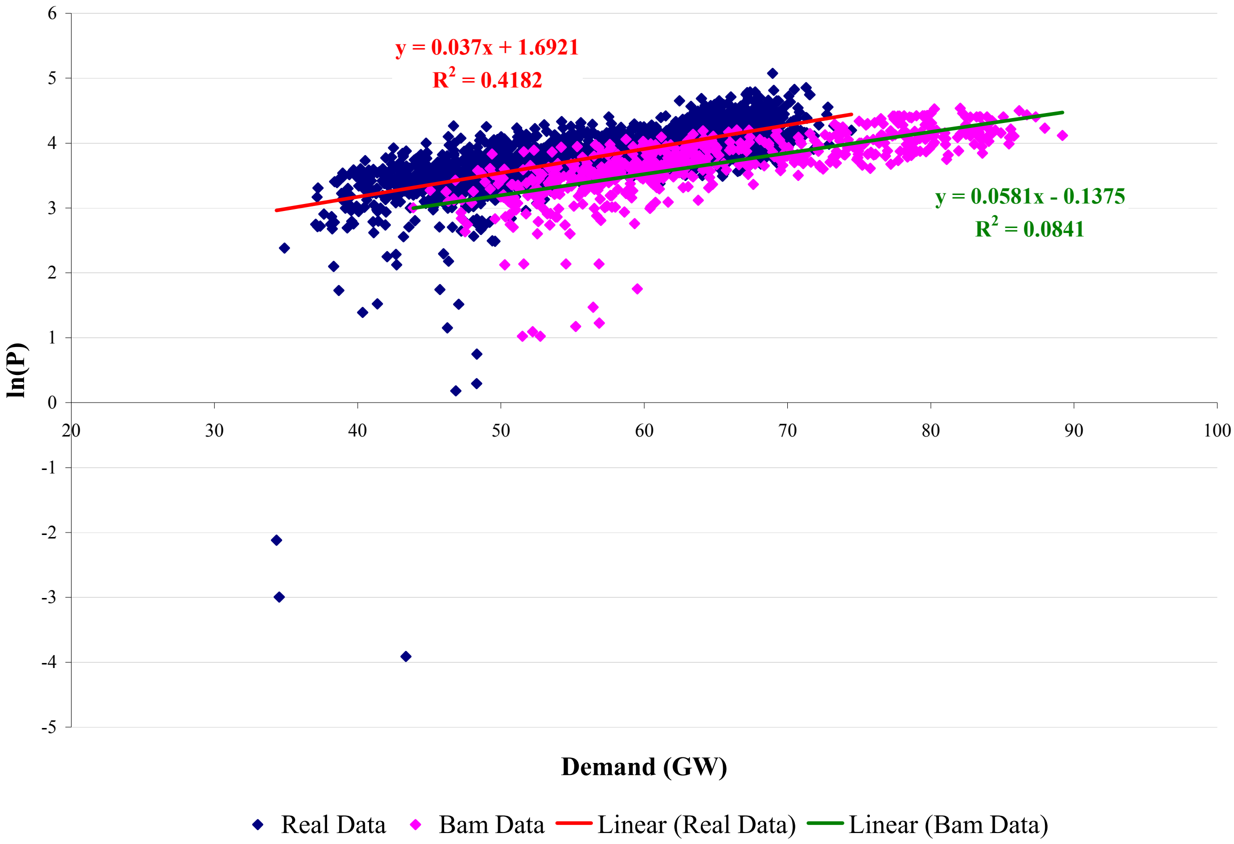


Figure 56: Natural log of actual 2009 summer prices for Germany and natural log of BAM 2009 summer prices for Germany plotted against corresponding German demand

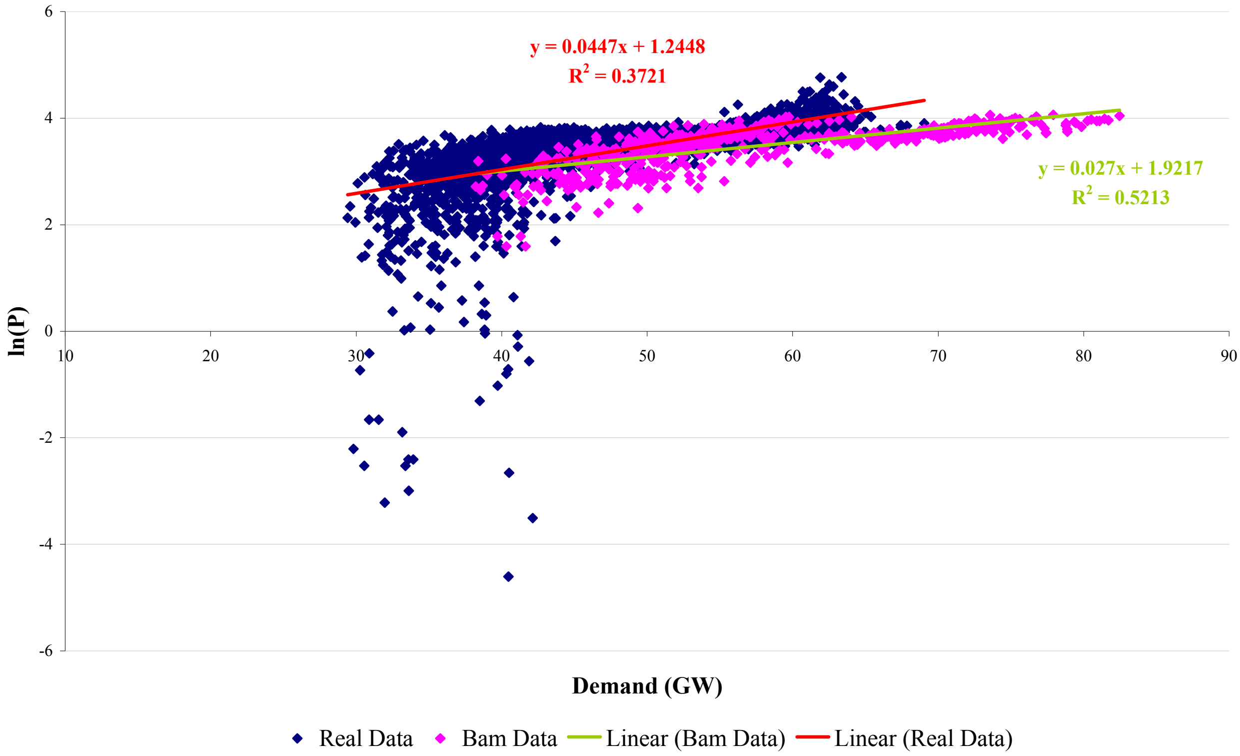


Figure 57: Natural log of actual 2009 winter prices for France and natural log of BAM 2009 winter prices for France plotted against corresponding French demand

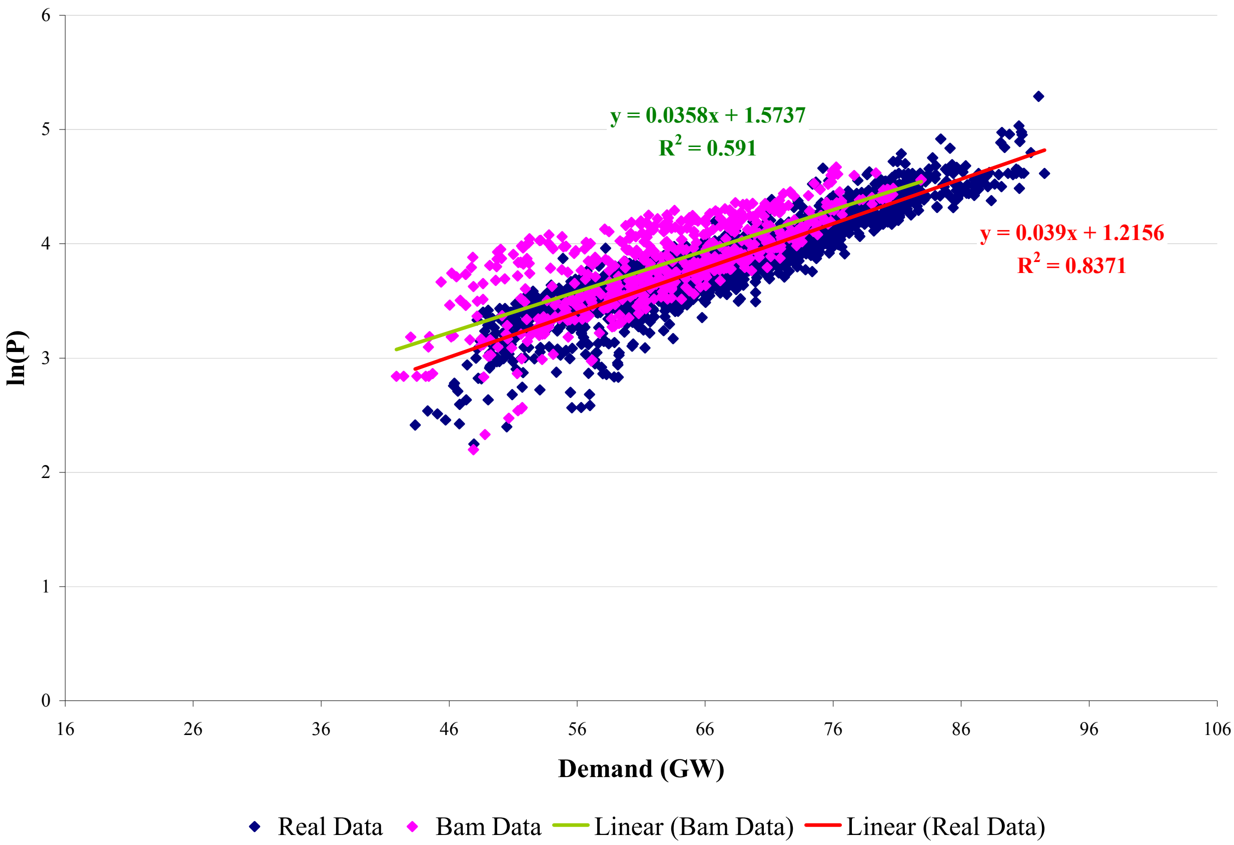


Figure 58: Natural log of actual 2009 summer prices for France and natural log of BAM 2009 summer prices for France plotted against corresponding French demand

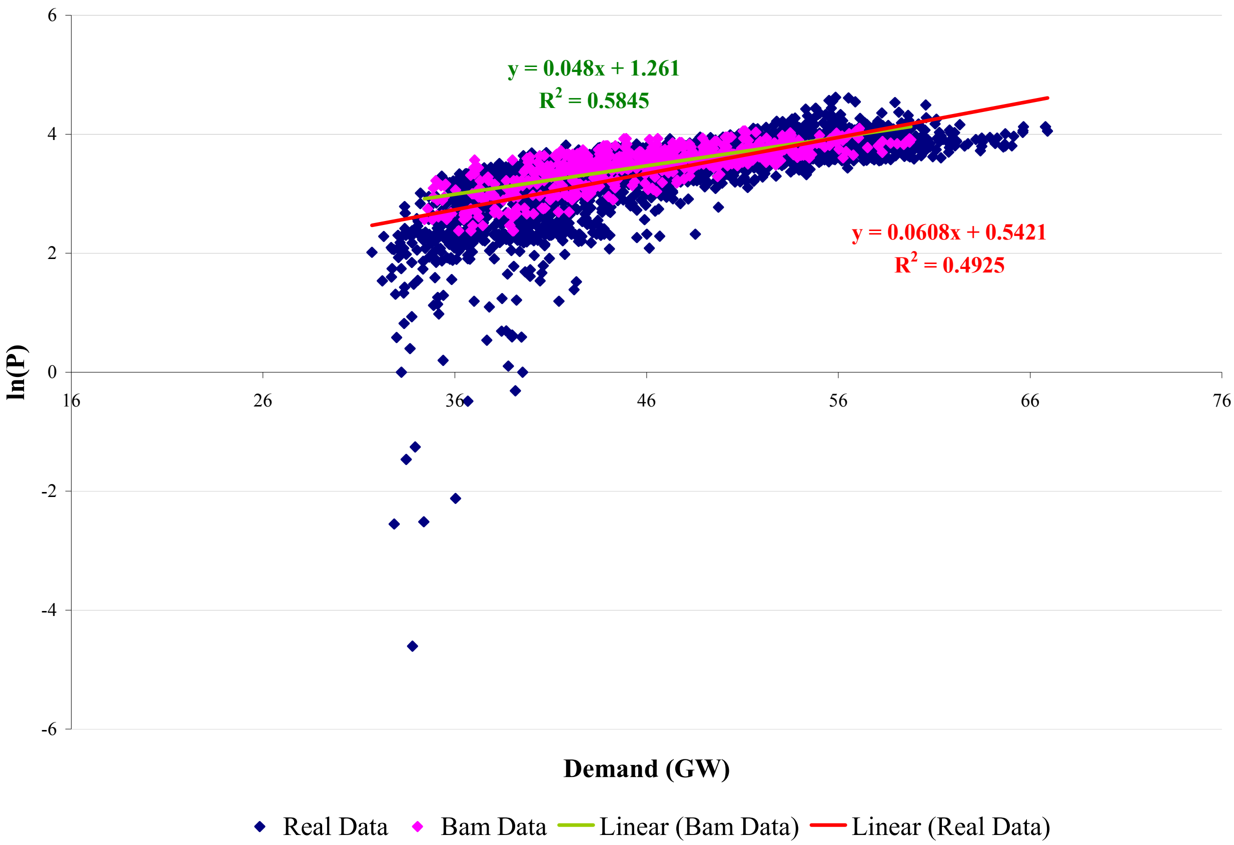


Figure 59: Natural log of actual 2009 winter prices for Belgium and natural log of BAM 2009 winter prices for Belgium plotted against corresponding Belgian demand

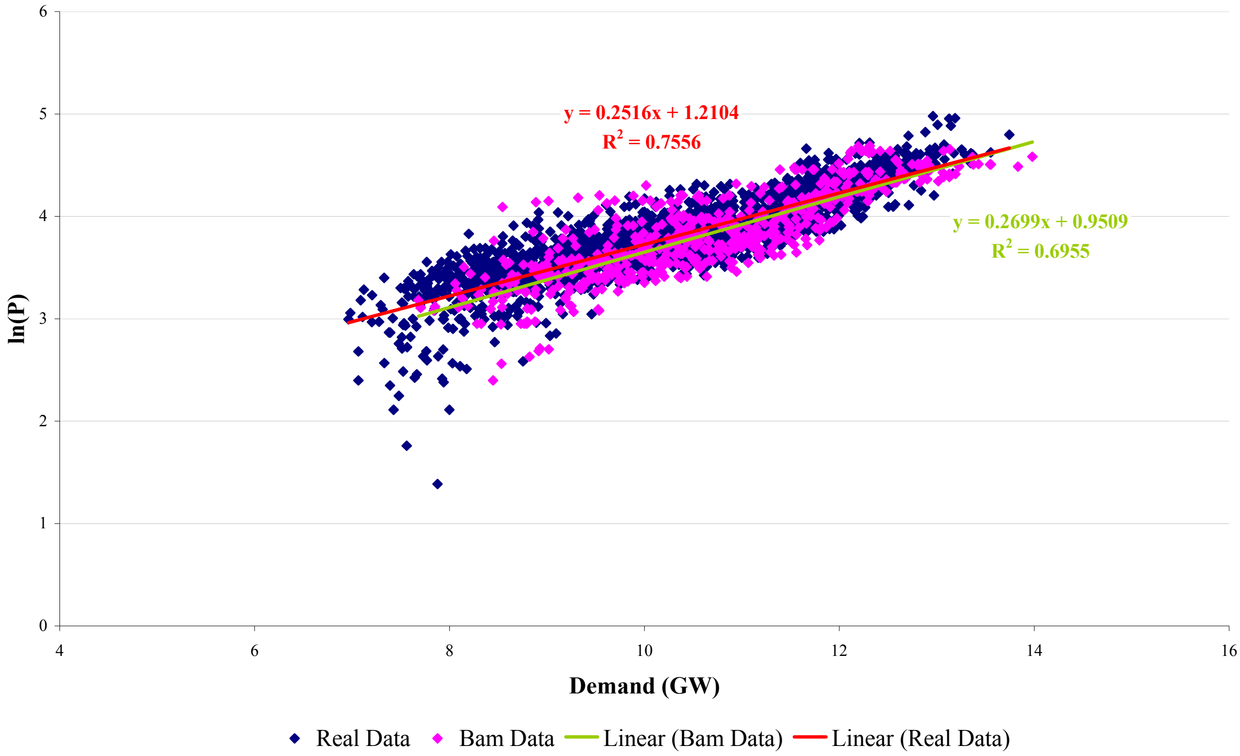


Figure 60: Natural log of actual 2009 summer prices for Belgium and natural log of BAM 2009 summer prices for Belgium plotted against corresponding Belgian demand

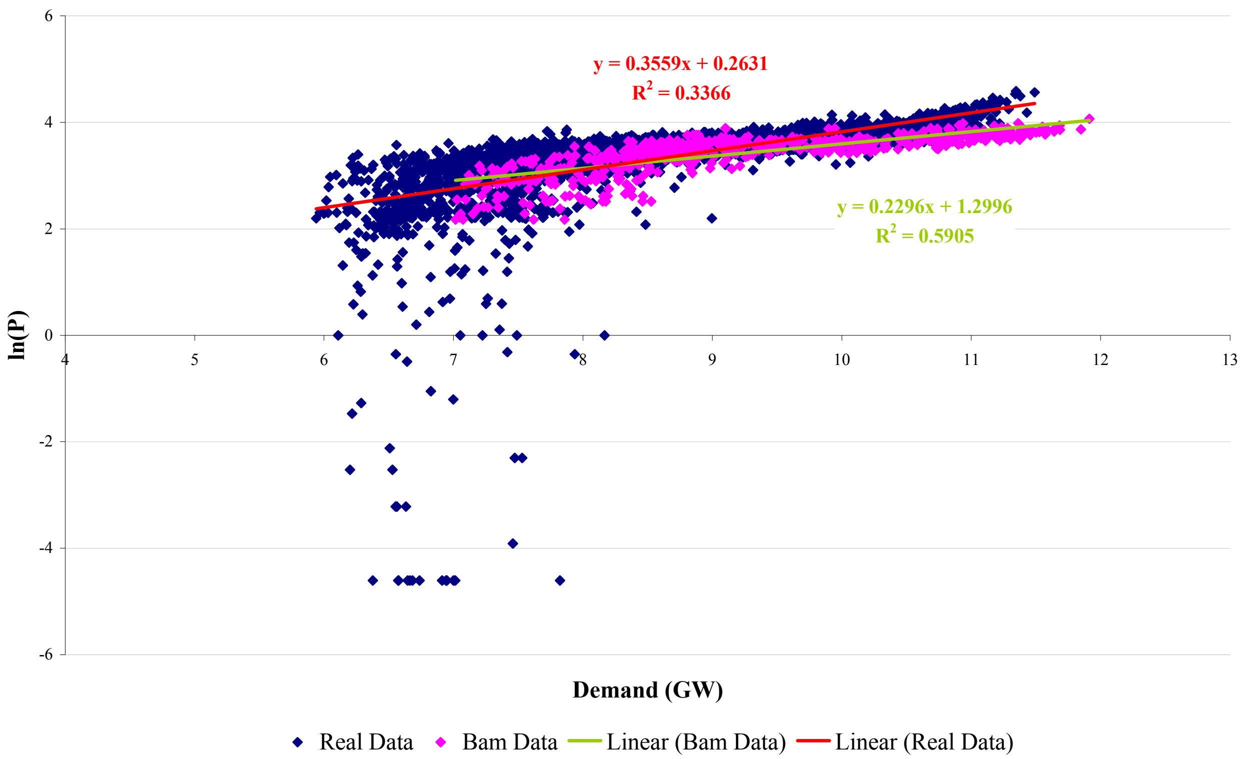


Figure 61: Natural log of actual 2009 winter prices for the Netherlands and natural log of BAM 2009 winter prices for the Netherlands plotted against corresponding Dutch demand

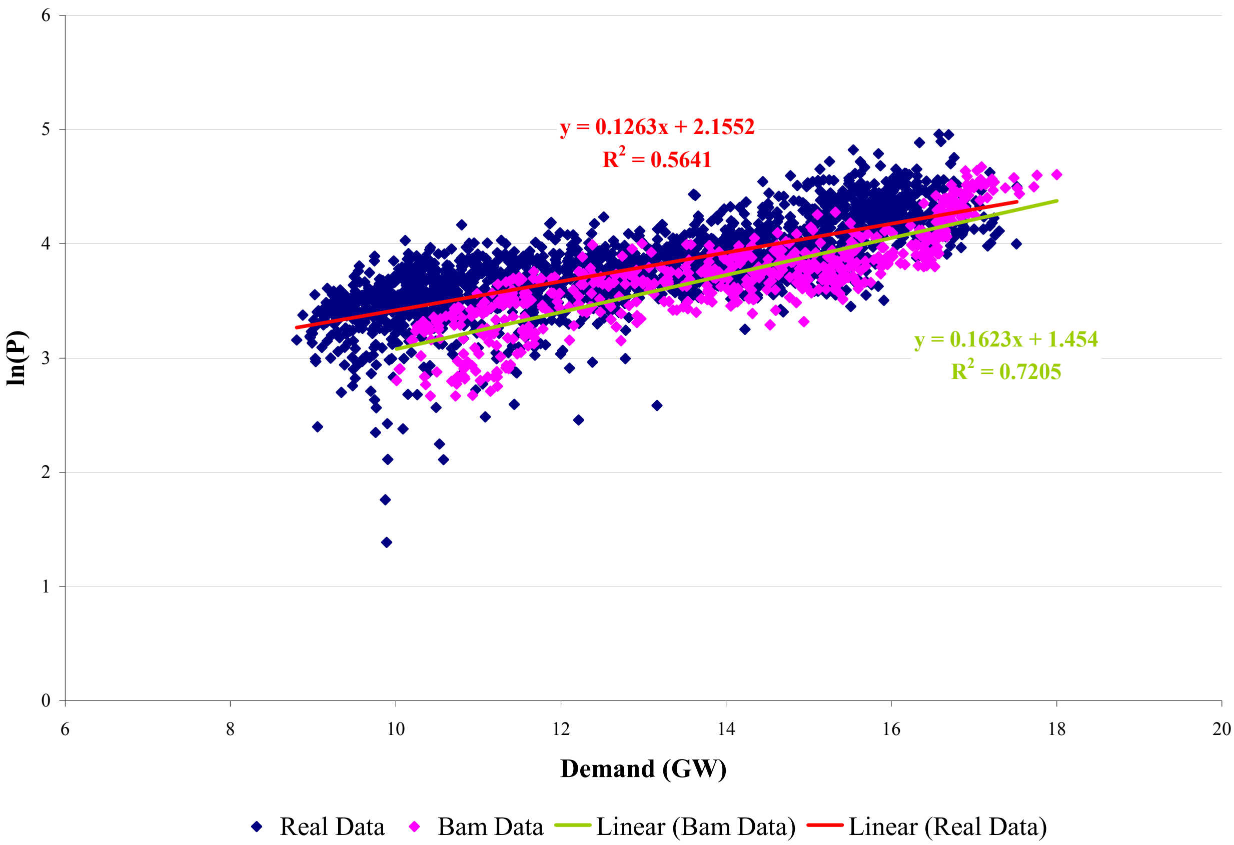
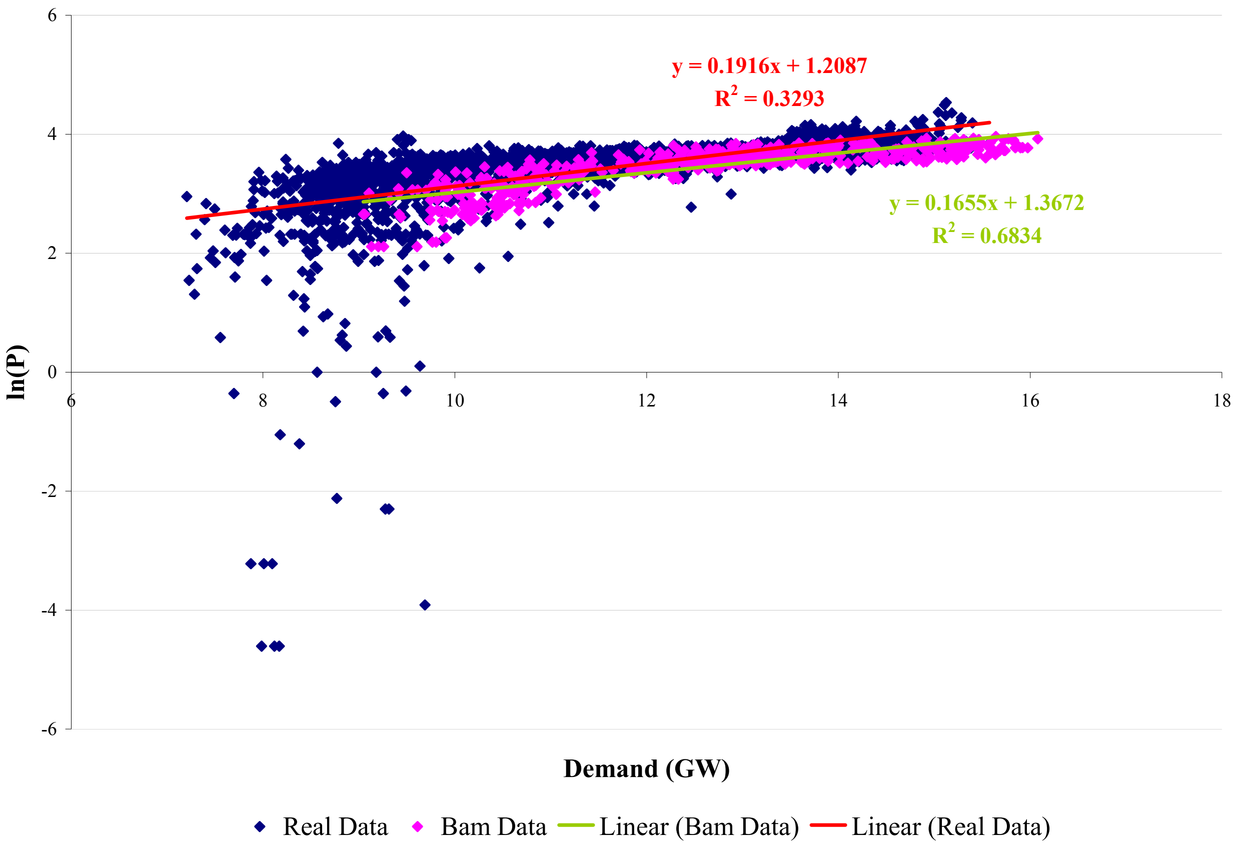


Figure 62: Natural log of actual 2009 summer prices for the Netherlands and natural log of BAM 2009 summer prices for the Netherlands plotted against corresponding Dutch demand



Appendix V : Probabilistic modelling methodology

As described in the main text, BAM includes three sources of volatility:

- Wind power output;
- Demand;
- Unplanned plant outages.

Below, we describe how we model each of these sources of volatility.

V.1. Random electricity production from wind farms

The goal of this part of the modelling is to generate a random series of Capacity Factors (CFs) for wind powered generation (WPG), which respect both the average day/night monthly CFs, and also respects correlations between CFs across countries. The CF is the percentage of power generated in an hour as a percentage of the maximum power that could be generated. The CF can be applied to the amount of installed capacity in each year modelled to estimate output from WPG.

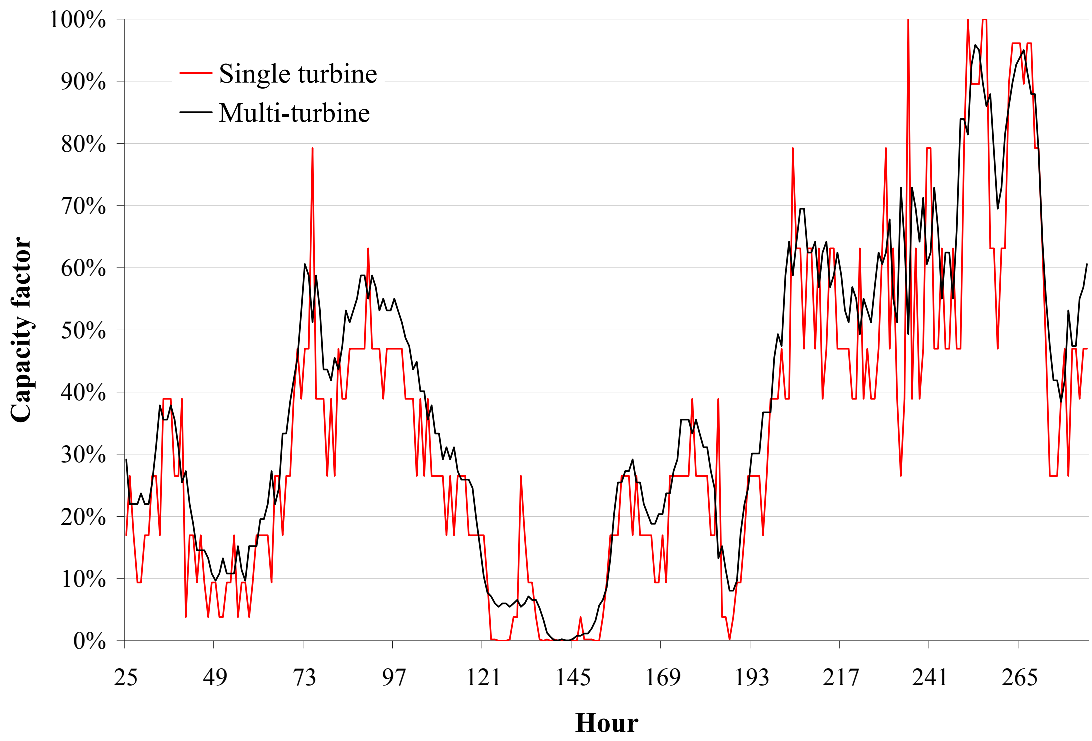
The first step is to examine the historic hourly changes in WPG for the countries modelled. We only have historic hourly data for WPG for Belgium. For the other countries, we needed to generate our own historic time series of electricity from WPG from hourly wind speed data for a site in each country. First, we used a power curve from a large manufacture of wind turbines to convert the wind speed into a Capacity Factor (CFs).[31] We then needed to account for the difference between the output from a single wind turbine and the difference from wind farms over a wide area. In essence, electricity production from WPG over a large area will be much smoother than production from a single wind farm, as changes in wind speed will tend to average out over the wider area. To create the simulated output from a wider area of wind farms from wind speeds at a single point, we used a technique described in an academic paper and presented at the 2004 Nordic wind power conference.[32] In essence, the technique calculates a rolling average wind speed, with the period over which the average is taken being a function of the wind speed itself. This simulates the average wind speed over the entire area being considered, based on the wind speed measured at a single point within the area. The technique also assumes that there is some random variation of wind speed within the area being considered, so that wind speeds can be both more or less than for the point measurement with a known probability. Using the rolling average effect and a distribution of wind speeds around the point measurement combine to ‘smooth’ the change in wind speeds and capacity factors. The estimated electricity production is more representative of an area of wind farms. Figure 63 illustrates the difference between the single and multi-turbine approaches – the figure shows that unlike the CF for a single turbine, the multi-turbine CF rarely reaches 0%, because somewhere in the area modelled the wind will be blowing sufficiently fast to generate power.

[31] The power curve was for a Vestas turbine. We found that there was little difference in the relationship between wind speed and CF for different turbine sizes, so our power curve is not specific to a particular turbine capacity.

[32] Per Norgardand HanneleHolttinen, A Multi-Turbine Power Curve Approach. Proceedings of Nordic Wind Power. Conference NWPC, 2004.

Similarly, the multi-turbine CF rarely reaches 100%, because the wind will not be blowing fast at all locations within the area studied.

Figure 63: Capacity factors for a single turbine and a multi-turbine approach, estimated from wind-speed data



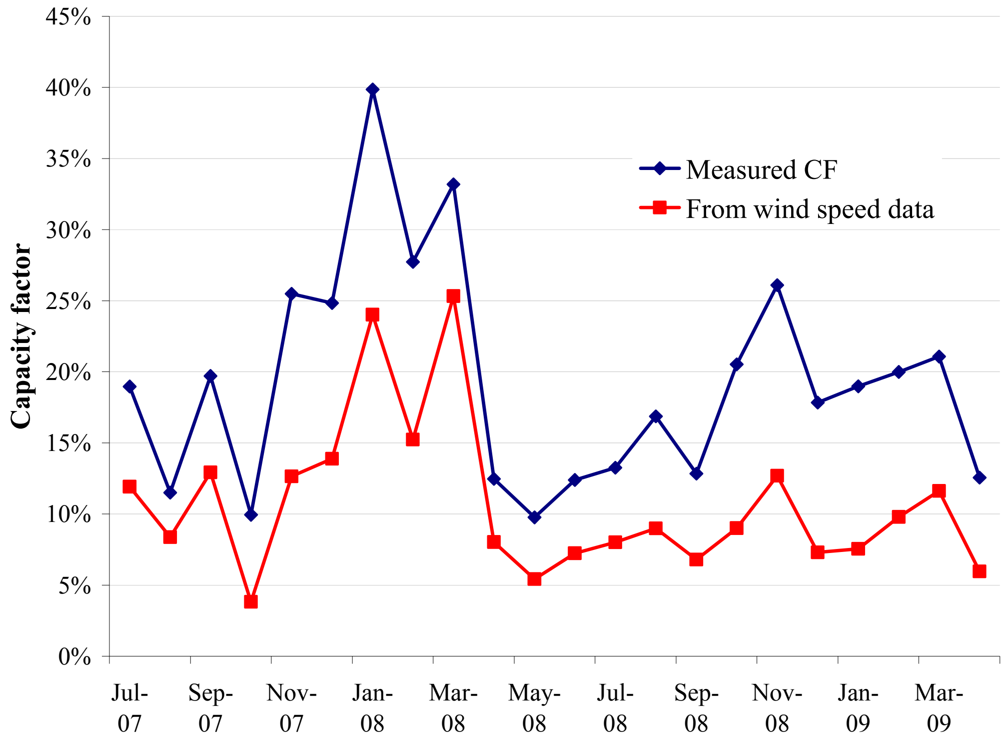
The next step is to calibrate the estimated wind output by comparing monthly average capacity factors from the multi-turbine approach to actual historic CFs. The CFs we estimate will be to low, because we are using wind speed measured from a weather mast, which is at a lower height (10 m) than the wind turbine (which will be at a height of over 30 m). Consequently the actual wind turbine will experience higher CFs than we estimate from our wind speed data.

However, we found that the ratio between the historic and estimated CFs was reasonably constant, and that the estimated CFs followed the historic CFs well, especially given the uncertainty in estimating historic CFs themselves.[33] Figure 64 illustrates both historic and estimated monthly CFs for Germany. Given this relatively constant relationship, we simply multiply the estimated CFs by a constant factor to correct for the hub height issue and approximate actual CFs. We also found that our estimated CF series for Belgium was a good match to the actual measured electricity production for WPG which Elia made available to us.[34]

[33] Historic monthly CFs can be difficult to measure especially when large amounts of WPG is being added to the system, since it can be difficult to match monthly WPG capacity with monthly WPG electricity production accurately.

[34] While we had actual WPG production data available for Belgium, in our modelling we used an estimated series of CF for Belgium so that we would have a consistent approach between all countries.

Figure 64: Estimated vs. historic CFs for Germany



The final step is to characterise the time-series of electricity production for WPG in a way that we can model probabilistically. We do this by having a function that can generate a random series of CFs, which still respect average historic CFs and changes in a realistic way.

The change in electricity production from wind from one hour to the next will depend on the current level of wind output, and the output in the previous hour. For example, if WPG is producing at a CF of 90% (*i.e.* near maximum capacity), it more likely that future changes will reduce rather than increase output. Similarly, if wind production is increasing, it is more likely to continue to increase in the next hour because a weather front is moving in.

To capture these effects, we use separate distributions for each 10% interval of CF (0%-10%, 10%-20% *etc.*),with a further separation for the cases where the previous hour had a higher or lower CF. In this way we generate 20 distributions of hourly CF changes. For example, we have a distribution of the hourly changes in CF when the CF in hour t was between 0 and 10% and the CF in hour t-1 was less than the CF in hour t. Similarly, we have a distribution of the hourly changes in CF when the CF in hour t was between 0 and 10% and the CF in hour t-1 was more than the CF in hour t. Depending on the CF in any hour, and the CF in the previous hour, we will draw an hourly change in CF from the relevant distribution.

While we assume that the volatility of the wind CFs is the same for all the countries, we adjust the average CF to approximate the monthly average CFs for each country seen in the historic data. We do this by applying mean reversion to the random series, to ensure that the monthly mean of the random distributions does not vary too much from the historic monthly average CFs used in the deterministic runs. For example, suppose the average CF is 35%, and the CF in hour t is 50% *i.e.* above the average.

If the random draw suggests that the CF should increase by +20%, which is further away from the average CF, then we apply a factor that will reduce the suggested change in CF to e.g. +10%. The adjustment to the randomly drawn change in CF gets larger the further the CF in hour t is from the desired average CF.

We use a different mean reversion for each month and for day-time periods (defined as 08:00 to 20:00 inclusive) and for night-time periods. This means that the higher average wind production in day-time hours is accounted for in the probabilistic modelling.

5.6.1. Correlation between wind farms

Correlations between the wind farm generation in each country are important. A lower degree of correlation will contribute to larger price differences between countries and hence higher Nemo interconnector revenues.

To ensure we get realistic correlations between CFs in the different countries modelled, we take the approach of generating a 'seed' time series and then generating other time series of CFs from the seed series, ensuring that the two series have the correct correlation. Specifically, we generate a random wind time series for Germany, using the distributions described above. We then generate a time-series for all the other countries from the Germany time series.[35] For each hour, we take the CF of the Bremen series and add to it a random change in the CF. The random change is drawn from a distribution, the parameters of which are set so that the correlation between the first and second time series are as required. We repeat this process to generate a series for each country, so the correlations between the time series are close to the historic correlations between the CFs of wind farms in these countries using our CFs derived from historic wind speed data. Table 54 compares the historic correlations with those from the random ('synthetic') time series, and shows that the synthetic series has a good match with the historic data. We also adjust the mean of the time series for countries other than Germany to ensure that they match the historic monthly CFs.

Note that the model only incorporates simple 'linear' correlations between Germany and the other countries. We have not tried to match the time series for correlations between, France and the Netherlands. On balance, including other correlations would increase the complexity of the model without necessarily adding accuracy. By focusing on correlations between WPG output in Germany and other countries, our simpler approach does capture the most important correlations for the value of the Nemo interconnector.

[35] Because Germany has such a large capacity of WPG by 2030 we actually model two time-series of CFs for Germany, so as to make German production more realistically random. Perhaps surprisingly, the historic hourly correlation between the two locations in Germany is only 0.76, about the same as the correlation between Germany and the Netherlands.

Table 54: Hourly correlations between Germany (Bremen) and other locations, for both the historic data and the random 'synthetic' time-series

Bremen vs.	From historic data	From synthetic data
Waren (DE)	0.76	0.76
NL	0.74	0.74
FR	0.31	0.33
GB	0.29	0.31
BE	0.55	0.54

V.2. Randomised Demand

We can take a more detailed statistical approach to modelling demand data relative to wind, because we have historical hourly demand data for all of the countries we are modelling: Belgium, the Netherlands, GB, Germany and France. We do not model randomised demand in Germany because we do not have German hourly demand data, so there would be nothing reliable on which to base a demand distribution.

We use the historical hourly electricity demand data from 2005 to establish a distribution of demand for each characteristic day. For example, we produce a distribution of demand for January weekdays, another distribution for January Saturdays and so on, giving 36 distributions in total.

In each country there is a typical pattern of demand for each day. To preserve this pattern, we prefer to uniformly increase or decrease demand across the whole day. For example, for a January weekday, we would take a random draw from the distribution of demand for January weekdays. Suppose the draw was 110% of the average demand for a January weekday – we would keep the average January weekday shape, but increase demand in all the 24 hours by the same percentage so that total demand on that day was 110% above average January weekday demand.

An alternative approach would be to break the data down further, by *e.g.* creating distributions of demand for a January weekday between 12:00 and 13:00. However, the difficultly with this approach is that we would then have to account for correlations between hours, to preserve the typical daily shape. For example, suppose that demand for a January weekday between 12:00 and 13:00 was 120% above the average; clearly the demand in the next hour is not independent – since it is likely the extra demand is caused by some persistent factor such as cold weather. We would have to account for the correlation between hours, a problem that would be excessively complex and likely to lead to unrealistic results, since it would be very difficult to preserve the 'typical' daily demand shape.

Similarly, we assume that all days are independent draws *e.g.* a draw for one January weekday will not affect the draw for the next day. While this is somewhat unrealistic – in reality there is likely to be correlations between consecutive days as *e.g.* cold weather persists – one must remember that for the value of the interconnector it is the correlations between Germany and Belgium on the same day that are important, not serial correlations between consecutive days. While our approach will produce a time series of demand that might not be wholly realistic, our methodology will not distort the value of the interconnector.

To capture demand correlations between countries, we use a multi-variate normal distribution. Whereas a normal distribution is specified by a mean and a standard deviation, the multi-variate normal distribution is specified by the mean of each of the variables and a variance/co-variance matrix. We specify a multi-variate distribution for each of the characteristic days, and use the historical hourly data to derive the means and the variance/co-variance matrix for demand.

We then draw at random from the multi-variate normal distribution, which produces a value for each country. The distribution automatically accounts for correlations between the four countries' demand by considering the co-variances between country demand data.

V.3. Plant outages

Instead of simply down rating the available capacity of each plant by its forced outage rate throughout the year, we randomly choose whether the plant is fully available or not on each day for each run that we perform. For example, suppose that a plant has a forced outage rate of 5% and we are interested in its availability on March weekdays, of which there are 20. We assume that once a plant is unavailable it will be unavailable for two days. Consequently, we make ten draws of a random number between 0 and 1. Every time the random number is equal to or below 0.025 i.e. half its forced outage rate, we will assume that the plant is totally unavailable for two days. Otherwise we will assume it is fully available for the two day period we are considering. We then add up all the days that it is available and divide by the total number of days considered to calculate the percentage availability to apply to the plant's installed capacity for that characteristic day. As an example, suppose that the plant was unavailable on 6 out of the 20 days, then the available capacity of the plant for that characteristic day will be 0.7 (=[20-6]/20).

Appendix VI : Estimating changes in welfare

Figure 65 illustrates how we calculate the change in producer and consumer welfare as a result of the new interconnection capacity between GB and Belgium. Figure 65 illustrates an example where prices increase as a result of the new interconnection capacity, but the same principles apply to a price decrease. The vertical line marked D represents domestic demand, and the upward-sloping line labelled S represents the supply curve.

Without the cable, prices are at level P1. Generators in the country produce Q1, and so are exporting (Q1 – D). After the cable is built, generators increase production to Q2 and exports to (Q2 – D). The cost of the marginal generator also increases, which causes prices to rise from P1 to P2. For consumers, the blue rectangle represents the reduction in welfare – it is simply the change in price multiplied by demand. For producers, the increase in welfare is the area represented the red triangle, the yellow square and the blue rectangle. As the Figure 65 illustrates, the change in producer welfare and the change in consumer welfare do not cancel one another out. The yellow square and the red triangle represent the net change in welfare.

In reality the supply curve is not linear, but rather a series of steps. Hence this methodology is an approximation, because it assumes a linear change in supply costs between point Q1 and point Q2. However, since the change in exports is usually quite small relatively to the entire supply curve, this approximation will not introduce a large error.

Figure 65: Example of welfare change

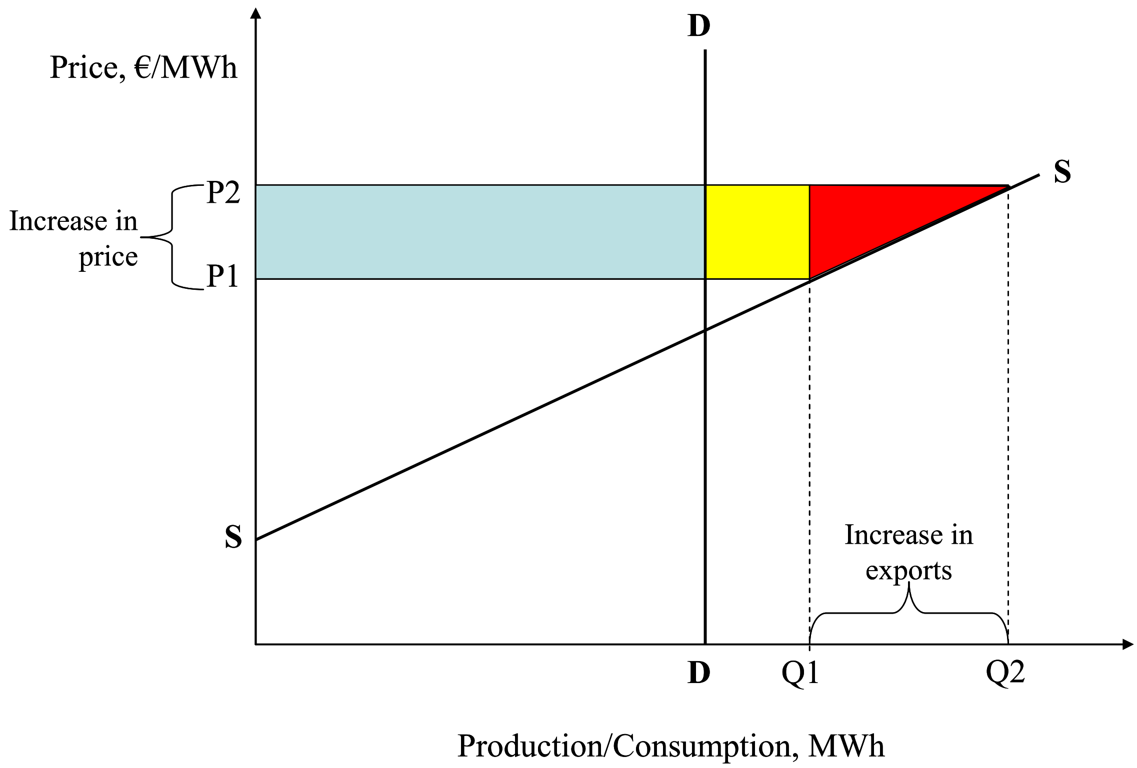
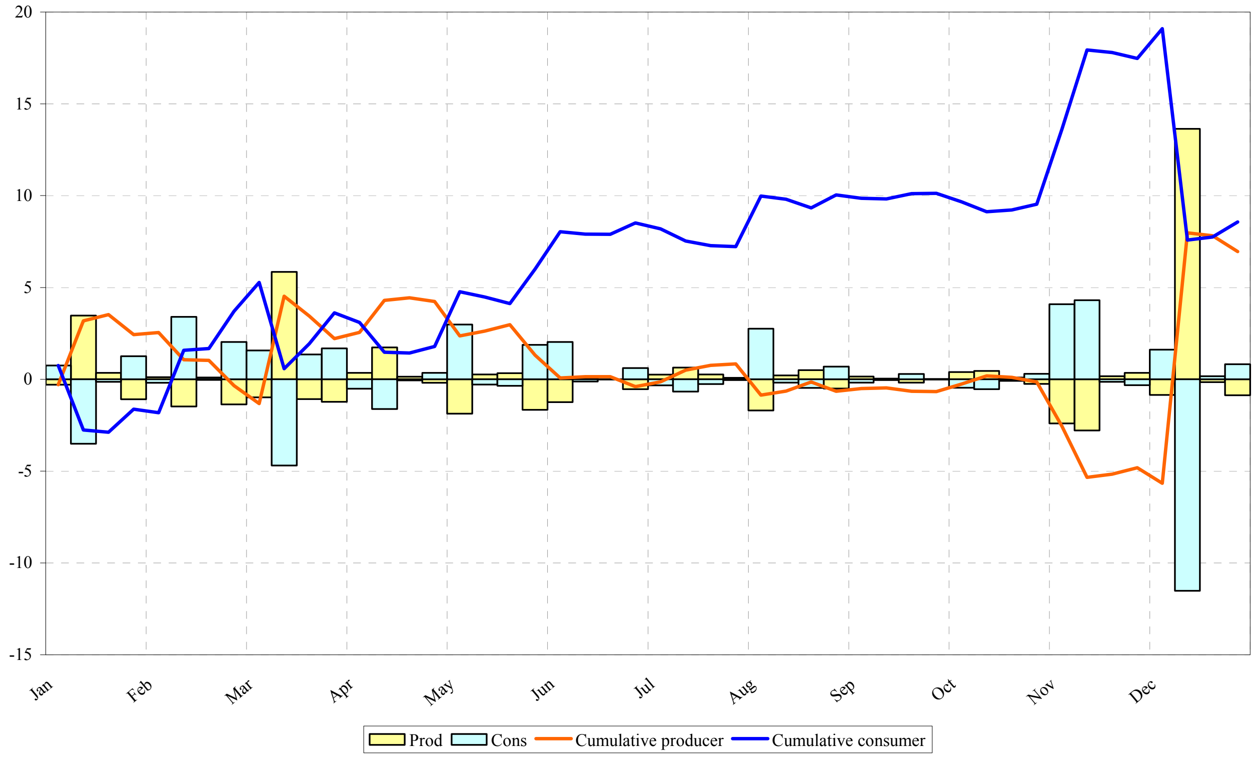


Figure 66 illustrates that the change in producer and consumer surplus will always have the opposite sign for any characteristic day even if they have the same sign over the course of a year. (Technically, this is only true for a characteristic hour but it generally holds also for a characteristic day).

Figure 66: Example of changes in consumer and producer welfare for specific day-types and cumulative changes in welfare, Belgium 2020



Appendix VII : Calculations for cold winter sensitivity

Table 55: Calculated increase in demand for cold winter in France

	HDD	Consumption	Forecasted consumption	% severe month
Constant [1]	31,298.97			
Coefficient [2]	37.95			
severe winter [3]	10%			
Max HDD Nov (1999-2009) [4]	357.96			
Max HDD Dec (1999-2009) [5]	456.3			
Max HDD Jan (1999-2009) [6]	508.55			
Max HDD Feb (1999-2009) [7]	407.15			
HDD severe Nov [8]	393.76			
HDD severe Dec [9]	501.93			
HDD severe Jan [10]	559.41			
HDD severe Feb [11]	447.87			
Demand for severe Nov [12]	46,244.02			
Demand for severe Dec [13]	50,349.55			
Demand for severe Jan [14]	52,530.99			
Demand for severe Feb [15]	48,297.53			
	HDD	Consumption	Forecasted consumption	% severe month
		GWh	GWh	%
	[A]	[B]	[C]	[D]
Jan-08	405.35	49858	46,683.89	12.52%
Feb-08	382.5	45267	45,816.62	5.41%
Nov-08	340	44212	44,203.55	4.62%
Dec-08	490.8	51428	49,927.11	0.85%

Notes and sources
[C]=[1]+[2] x [A]
[B] from Entso
[1] and [2] from regression [B]=a + b x [A]
[4] - [7] = max of HDD data (1998-2009) for that month
[3]: assumption
[8] - [11] = [4]-[11] x (1 + [3])
[12] - [15] = [1]+[12]-[15] x [2]
[D]=([12] - [C])/[12]

Table 56: Calculated increase in demand for cold winter in Belgium

Constant [1]	6,510.06			
Coefficient [2]	3.18			
severe winter [3]	10%			
Max HDD Nov (1999-2009) [4]	353.52			
Max HDD Dec (1999-2009) [5]	474.10			
Max HDD Jan (1999-2009) [6]	548.00			
Max HDD Feb (1999-2009) [7]	430.68			
HDD severe Nov [8]	388.87			
HDD severe Dec [9]	521.51			
HDD severe Jan [10]	602.80			
HDD severe Feb [11]	473.75			
Demand for severe Nov [12]	7,747.54			
Demand for severe Dec [13]	8,169.63			
Demand for severe Jan [14]	8,428.32			
Demand for severe Feb [15]	8,017.65			
	HDD	Consumption GWh	Forecasted consumption GWh	% severe month %
	[A]	[B]	[C]	[D]
Jan-08	405.35	8398	7,799.98	8.1%
Feb-08	382.5	7930	7,727.27	3.8%
Nov-08	340	7373	7,592.03	2.0%
Dec-08	490.8	7501	8,071.91	1.2%

Notes and sources
[C]=[1]+[2] x [A]
[B] from Entso
[1] and [2] from regression [B]=a + b x [A]
[4] - [7] = max of HDD data (1998-2009) for that month
[3]: assumption
[8] - [11] = [4]-[11] x (1 + [3])
[12] - [15] = [1]+[12]-[15] x [2]
[D]=([12] - [C])/[12]

Table 57: Calculated increase in demand for cold winter in Germany

Constant [1]	41,558.73			
Coefficient [2]	16.69			
severe winter [3]	10%			
Max HDD Nov (1999-2009) [4]	402.30			
Max HDD Dec (1999-2009) [5]	511.70			
Max HDD Jan (1999-2009) [6]	608.60			
Max HDD Feb (1999-2009) [7]	478.25			
HDD severe Nov [8]	442.53			
HDD severe Dec [9]	562.87			
HDD severe Jan [10]	669.46			
HDD severe Feb [11]	526.08			
Demand for severe Nov [12]	48,942.80			
Demand for severe Dec [13]	50,950.79			
Demand for severe Jan [14]	52,729.36			
Demand for severe Feb [15]	50,336.83			
	HDD	Consumption GWh	Forecasted consumption GWh	% severe month %
	[A]	[B]	[C]	[D]
Jan-08	405.35	52096	48,322.41	9.1%
Feb-08	382.5	49868	47,941.13	5.0%
Nov-08	340	46428	47,231.98	3.6%
Dec-08	490.8	45582	49,748.23	2.4%

Notes and sources
[C]=[1]+[2] x [A]
[B] from Entso
[1] and [2] from regression [B]=a + b x [A]
[4] - [7] = max of HDD data (1998-2009) for that month
[3]: assumption
[8] - [11] = [4]-[11] x (1 + [3])
[12] - [15] = [1]+[12]-[15] x [2]
[D]=([12] - [C])/[12]

Appendix VIII : Details of competition analysis

Table 58: Assumed plant ownership for Belgium conventional plants

Plant	Owner	Capacity (MW)
TIHANGE 3	Electrabel	1,055
TIHANGE 2	Electrabel	1,008
TIHANGE 1	Electrabel	962
DOEL 4	Electrabel	1,025
DOEL 3	Electrabel	1,006
DOEL 2	Electrabel	433
DOEL 1	Electrabel	432
AMYLUM Aalst	Electrabel	48
BAYER WKK	Electrabel	43
BP Chembel Geel	Electrabel	43
DEGUSSA	Electrabel	43
DROGENBOS GT1	Electrabel	465
ESCH-SUR-ALZETTE STEG	Electrabel	376
FINA 1	Electrabel	129
HERDERSBRUG GT1	Electrabel	465
LANGERBRUGGE 30	Electrabel	38
LANGERLO 1	E.On	142
LANGERLO 2	E.On	76
MONSANTO	Electrabel	43
PHENOLCHEMIE	Electrabel	23
RUIEN 5 REPOWERING	Electrabel	43
SAINT-GHISLAIN STEG	Electrabel	350
SAPPI	Electrabel	43
SLECO	Electrabel	39
SOLVAY Jemeppe GT1	Electrabel	86
TJ BEERSE	Electrabel	37
TJ TURON	Electrabel	20
TJ VOLTA-IXELLES	Electrabel	36
VILVOORDE GT	E.On	385
VPK OUDEGEM	Electrabel	15
Zandvliet Power	Electrabel	395
ZEEBRUGGE WKK	Electrabel	41
INESCO GT1	RWE	133
ANGLEUR TG31	SPE	37
HAM-GENT GT	SPE	52
HARELBEKE D 1	SPE	73
RINGVAART STEG	SPE	357
SERAING TG1	SPE	400
Antwerp cogen	Nuon	298
Small Gas	Electrabel	43
EXXONMOBIL	Electrabel	140
LANXLESS	Electrabel	64
IZEGEM	SPE	22
HAM 31	SPE	104
Rodenhuize	Electrabel	300
Amercoeur-Charleroi	Electrabel	410
Tessenderlo Chemie	T-Power	400
Seneffe	Nuon	400
Marcinelle CCGT	Enel	65
West Flanders	Thenergo	16
Merksplas	Thenergo	78
Liège	Electrawinds	34
Oostende	Eneco	19
Zwijndrecht	Electrabel	55
Olen	Umicore	12
Antwerpen Degussa	Electrabel	42
Marcinelle	Enel	303
Navagne	SPE	900
Genk-Zuid	RWE	400
New CCGT 01	New	604
New CCGT 02	New	400
New CCGT 03	New	400
New Rew 02	New	629
New Rew 06	New	305
Total		**16,838**

Table 59: Overall ownership assumptions for BE

Owner	Conventional capacity (MW)	Renewable capacity (MW)			Total capacity (MW)	Market Share (%)
		Hydro	Wind	Solar		
Electrabel	9,795	1,320	87		11,203	57.5%
SPE	1,945	42	27		2,014	10.3%
Nuon	698		1		698	3.6%
E.on	603		0		603	3.1%
RWE	533		0		533	2.7%
T-Power	400		0		400	2.1%
Enel	368		0		368	1.9%
Electrawinds	34		193		227	1.2%
Eneco	19		159		178	0.9%
Belwind NV/SA	0		58		58	0.3%
C-Power	0		113		113	0.6%
Eldepasco	0		76		76	0.4%
Thenergo	94		0		94	0.5%
Aspiravi NV	0		25		25	0.1%
Infrabel, S.A. / N.V.	0		9		9	0.0%
Umicore	12		0		12	0.1%
Gislom NV	0		3		3	0.0%
Renewable Power Co. Sprl	0		2		2	0.0%
Ecopower Cvba	0		1		1	0.0%
Middelwind CVBA	0		0		0	0.0%
Interelectra cvba	0		0		0	0.0%
Colruyt	0		0		0	0.0%
PBE Provinciale Brabançonne d`Energie	0		0		0	0.0%
GRC Kallo NV	0		0		0	0.0%
Total allocated capacity	14,500	1,362	755	0	16,617	85.2%
New Capacity Additions	2,338		426	112	2,876	14.8%
Total	**16,838**	**1,362**	**1,181**	**112**	**19,493**	100.0%

Table 60: Assumed plant ownership for GB conventional plants

Plant	Control Owner	Capacity (MW)
New Nuclear 01	New	1,200
Hinkley Point B	EdF	1,009
	Centrica	252
Hunsterston B	EdF	859
	Centrica	215
Torness	EdF	972
	Centrica	243
Sizewell B	EdF	960
	Centrica	240
Aberthaw B	RWE	1,094
Didcot A (G)	RWE	1,009
Drax	Drax banks	3,870
Longannet	Scottish Power	1,757
Lynemouth	ALCAN	160
Rugeley B	GdF	498
Tilbury B	RWE	1,057
Uskmouth	Welsh Power	376
Indian Queens	AES	140
Baglan Bay	BP	552
Barking	Thames Power	1,000
Barry	Centrica	245
CDCL	E.On	395
Connahs Quay	E.On	1,380
Corby	E.On	401
Coryton	InterGen	800
Damhead Creek	Scottish Power	805
Deeside	GdF	164
Derwent	Mitsui	228
Deeside	GdF	341
Didcot B 1	RWE	1,550
Drakelow D	E.On	1,320
Brimsdown	E.On	408
Grangemouth	BP	120
Great Yarmouth	BP	420
Immingham	Conoco	719
Immingham 2	Conoco	601
Fife Energy	SSE	123
Grain B Set No. 1	E.On	1,290
Langage	Centrica	905
Little Barford	RWE	665
Marchwood	ESBI	900
Medway	SSE	700
Shotton Paper	GdF	210
Pembroke II	RWE	600
Peterborough	Centrica	405
Peterhead	SSE	1,524
Rocksavage	SSE	810
Teesside 1	GdF	614
Roosecote	Centrica	320
Rye House	Scottish Power	715
Saltend	GdF	367
Fawley Cogen	RWE	158
Littlebrook	RWE	1,000
Saltend	GdF	733
Seabank	BG	820
Wilton	Sembcorp	60
Seabank 2	BG	414
Severn Power	Dong Energy	801
Shoreham	Scottish Power	420
South Humber Bank	Centrica	1,285
Spalding	Centrica	880
Staythorpe C	RWE	1,700
Sutton Bridge	EdF	800
West Burton B	EdF	335
Small Oil	Various	62
Small Gas	Various	22
Brigg	Centrica	260
Sellafield	BNFL	155
Steven's Croft	E.On	97
Baglan Bay	SSE	435
New CCGT 1	New	435
New CCGT 2	New	455
New Coal 1	New	1,966
Drax biomass	Drax banks	290
New Rew	New	3,808
New Coal 2	New	2,000
New Coal 3	New	2,000
New Coal 4	New	2,000
Total		**60,899**

Table 61: Overall de-rated capacity ownership assumptions for GB

Owner	Conventional capacity (MW)	Renewable capacity (MW)		Total capacity (MW)	Market Share (%)
		Hydro	Wind		
AES	140	0	0	140	0.2%
ALCAN	160	0	0	160	0.2%
AMEC	0	0	103	103	0.1%
Argyll Wind Farms	0	0	8	8	0.0%
Baillie Wind Farm	0	0	11	11	0.0%
Beaufort Wind	0	0	4	4	0.0%
Beinn Mhor Power	0	0	60	60	0.1%
BG	1,234	0	0	1,234	1.7%
BNFL	155	0	0	155	0.2%
Boulfrich Wind Farm	0	0	3	3	0.0%
Boyndie Co-op	0	0	4	4	0.0%
BP	1,092	0	0	1,092	1.5%
Centrica	5,250	0	443	5,693	7.9%
Community Wind Power	0	0	10	10	0.0%
Conoco	1,320	0	0	1,320	1.8%
Delta Petroleum Group	0	0	529	529	0.7%
Dong Energy	801	0	274	1,075	1.5%
Drax banks	4,160	0	0	4,160	5.8%
Duke Energy	0	0	15	15	0.0%
E.On	5,291	0	220	5,511	7.7%
Ecoventures	0	0	28	28	0.0%
EdF	4,935	0	16	4,951	6.9%
Eneco	0	0	3	3	0.0%
ESBI	900	0	0	900	1.3%
Eurus Energy	0	0	6	6	0.0%
Falck Renewables	0	0	31	31	0.0%
Fred. Olsen Renewables	0	0	91	91	0.1%
Gamesa	0	0	20	20	0.0%
GdF	2,927	2,004	0	4,931	6.9%
Good Energies	0	0	2	2	0.0%
Green Power	0	0	53	53	0.1%
Iberdrola	0	0	4	4	0.0%
Infinenergy	0	0	4	4	0.0%
InterGen	800	0	0	800	1.1%
Kingsburn Wind Energy	0	0	4	4	0.0%
Masdar	0	0	70	70	0.1%
Mitsui	228	0	0	228	0.3%
NBW Wind Energy	0	0	40	40	0.1%
Norsk Hydro	0	0	55	55	0.1%
North British Windpower	0	0	29	29	0.0%
Novera/Infinis	0	0	32	32	0.0%
Pentland Road Windfarm	0	0	3	3	0.0%
PM Renewables	0	0	14	14	0.0%
RDC	0	0	6	6	0.0%
RES	0	0	29	29	0.0%
RWE	8,833	0	741	9,574	13.3%
Scottish Power	3,697	526	390	4,613	6.4%
Sembcorp	60	0	0	60	0.1%
Shira Wind	0	0	10	10	0.0%
Siemens	0	0	26	26	0.0%
SLP Energy	0	0	28	28	0.0%
SSE	3,592	988	658	5,238	7.3%
Stadtwerke München	0	0	77	77	0.1%
Statkraft	0	0	15	15	0.0%
Thames Power	1,000	0	0	1,000	1.4%
Triodos Investment Management	0	0	19	19	0.0%
Vattenfall	0	0	217	217	0.3%
Viking Energy	0	0	30	30	0.0%
Welsh Power	376	0	0	376	0.5%
West Coast Energy	0	0	13	13	0.0%
Wind Energy	0	0	34	34	0.0%
Wind Energy (Hearthstanes)	0	0	16	16	0.0%
Wind Prospect	0	0	19	19	0.0%
Allocated capacity	46,951	3,518	4,514	54,983	76.4%
Unallocated capacity	13,948	0	3,012	16,960	23.6%
Total	**60,899**	**3,518**	**7,526**	**71,943**	100.0%