INTERCONNECTION ECONOMIC FEASIBILITY REPORT

www.eirgrid.com

Published November 2009

DISCLAIMER

COPYRIGHT NOTICE

Front cover images: The images show a sample interconnector cable as well as elements of the cable laying process both on-land and at-sea. They have been provided courtesy of ABB. See www.ABB.com for more information.

FOREWORD

I am pleased to present this Interconnection Economic Feasibility Report, which assesses the economic benefits of greater interconnection from Ireland to Great Britain or France. It analyses a wide range of scenarios to identify the drivers for greater interconnection and how this would impact power system costs. It is expected that the report will provide the basis for further more detailed work, leading ultimately to a decision on future investments in interconnection.

EirGrid is currently developing the 500MW East-West Interconnector, from Woodland in Co. Meath to Deeside in North Wales, for completion in 2012. Together with the existing Moyle Interconnector, this will bring total interconnection capacity between the island of Ireland and Great Britain to 1000MW.

The potential benefits of further interconnection and the concomitant market enlargement are well understood, and include enhanced security of supply, increased competitiveness, reduced production costs, and the ability to integrate greater quantities of renewable generation resources. For these reasons emerging EU policy is to support further interconnection between power grids, leading to enhanced market integration, first at regional level but ultimately across Europe as a whole.

Against this background, this report assesses the impact of additional interconnection on the electricity system over the next 16 years. It provides a framework that can be used to develop policy for future interconnection and to inform investment decisions. Substantial benefits are identified and quantified, and a prima facia economic case for further interconnection is established. The report concludes with a list of next steps. EirGrid recommends that a work programme be initiated to produce detailed costings for further interconnection. EirGrid further recommends that there is engagement with responsible agencies on the island of Ireland and abroad to create a framework for funding of new interconnectors.

In parallel with this study, EirGrid is also conducting a number of other workstreams that ultimately will feed into the decision on future interconnector investment. A study is underway in Ireland to develop an offshore wind integration strategy in the event that the offshore sector develops beyond the immediate Gate 3 applications. We are also involved, under the auspices of the Renewable Energy Development Group (REDG), in an assessment of the feasibility of developing a significant renewable energy export industry. These potential developments have implications for the design of future interconnection and will be considered in the next, more detailed phase of work.

We welcome and value your feedback on this report. We hope this will generate a constructive debate on the best ways of progressing greater interconnection with our neighbours.

Dermot Byrne

Dermot Byrne

Chief Executive, EirGrid

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 EXECUTIVE SUMMARY

1.1 KEY MESSAGES

This report examines the economic feasibility of interconnection between the island of Ireland (the All-island (AI) system) and Great Britain or France. The benefits are classified under two headings: production cost savings and capacity benefits. The following are key messages to emerge, based on the assumptions[1] in the report:

1. This report reinforces the very strong economic case for the East-West Interconnector, currently under development.
2. A further (third) 500MW interconnector between AI and GB is economically attractive by 2020, and more so in 2025.
3. A fourth 500MW interconnector between AI and GB is economically feasible by 2025 in some scenarios, such as High Renewables.
4. A 500MW and 2 x 500MW interconnection between AI and France was modelled in 2015, 2020, and 2025. These studies indicated high capacity factor for the Ireland-France interconnector, and corresponding reductions in production cost. However, these results need to be corroborated by more detailed modelling before any recommendations could be made on Ireland - France interconnection.
5. In general, interconnection becomes more economically attractive further out in time. A High Renewables scenario improves the case for interconnection.
6. The incremental benefits of interconnection decrease with each subsequent interconnector.
7. The production cost savings that are evaluated in this report are the total benefits to both sides; savings are not apportioned between the parties. EirGrid recommends that there is engagement with responsible agencies on the island of Ireland and abroad to create a framework for funding of new interconnectors.

1.2 BACKGROUND

In response to the White Paper “Delivering a Sustainable Energy Future for Ireland”, EirGrid has carried out an assessment of the costs and benefits of further interconnection between the island of Ireland and Great Britain or France (in addition to the Moyle Interconnector and the planned East-West Interconnector). In carrying out this assessment, EirGrid has examined a broad range of scenarios such as number of interconnectors, different fuel prices and different generation portfolios.

Interconnection between the all-island power grid and other grids has the potential to deliver numerous benefits to the island. In particular, interconnection enhances security of supply, promotes competition in the electricity sector and facilitates the expansion of renewable energy generation. The Moyle Interconnector connects the electricity grids of Northern Ireland and Scotland in Great Britain. It has a capacity of 500MW and currently is capable of importing 450MW in winter and 400MW in summer from Scotland. However, the Moyle Interconnector is limited by contractual arrangements to an export capacity to Scotland of 80MW. This restriction is being reviewed at the moment, and we have assumed the export capability is increased to 400MW for our study.

[1] *See Chapter 4 for all of the input assumptions*

EirGrid is currently developing the 500MW East-West Interconnector to Great Britain. This has a scheduled completion date of 2012. For the purposes of these studies we are assuming that the island of Ireland will have, as a minimum, 900MW of interconnection with Great Britain.

Renewable generation, particularly wind, will provide a large proportion of the island of Ireland's energy needs in years to come. There are many challenges to overcome in order to efficiently accommodate this. The 2020 All-Island Grid Study demonstrated how necessary and useful the Moyle and East-West Interconnectors are for the integration of high levels of renewable generation. This report advances this work further to examine the benefits from additional interconnection for a range of plant portfolios out to 2025.

1.3 INPUT ASSUMPTIONS

1.3.1 Costs

Capital costs associated with interconnector projects are considerable. In order to transmit power over longer distances underwater, the use of High Voltage Direct Current (HVDC) cable is required. Converter stations at both ends of the cable are required to convert electricity from AC to DC and back again. Figure 1.1 shows the main components of a HVDC interconnection scheme.

It should be noted that total costs will vary, due to different locations, length of interconnection, technologies selected, market conditions and other factors. Bearing this in mind, we have calculated a reasonable range of capital costs that are used as a screening test to evaluate the different scenarios.

For an Ireland-Great Britain 500MW interconnector, the range of costs is €36 - €43m annualised.

An interconnector to France would cover a much longer distance. The capital costs are therefore significantly increased.

For an Ireland-France 500MW interconnector, the range of costs is €55 - €66m annualised.

This is a preliminary estimate; a more accurate value would require further work.

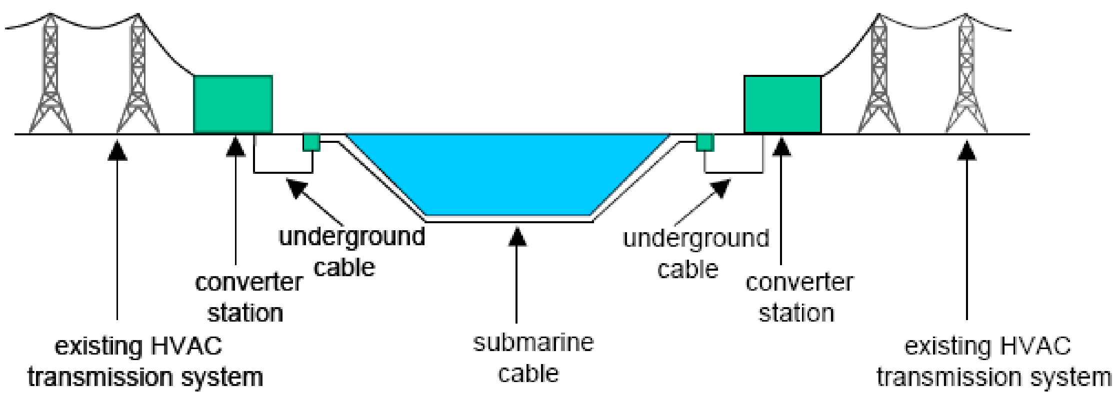

Figure 1.1 Components of a HVDC interconnection scheme.

1.3.2 Interconnection Size

We have used the East-West Interconnector as the model of the most suitable interconnection in the market at the moment for Ireland's power system. Hence, we have opted for an interconnector size of

500MW. There are disadvantages with a larger interconnector size as the power system would have to carry enough reserve to cater for its loss. With Moyle and East-West giving a total interconnection of 900MW with Great Britain, we have modelled an additional 1000MW with Great Britain in two blocks of 500MW each. For France, we have done the same by modelling up to 1000MW interconnection in blocks of 500MW.

1.3.3 Study Years

The case for additional interconnection is examined for three sample years in the future. Due to the development timeframe required, it was considered unlikely that further interconnection could be in place long before 2015. As a result, this is the earliest year chosen for analysis. 2020 and 2025 were also selected for analysis to enable reasonably significant changes to occur in terms of the generation portfolio, fuel/carbon prices etc.

1.3.4 Generator Portfolio: Ireland

In this study, the Ireland and Northern Ireland systems are modelled at generator level i.e. every conventional generator is modelled in detail and wind and wave powered generation are modelled using hourly power series. The generation portfolio for each study year is explicitly specified.

There is a relatively high degree of certainty as to the all-island generation portfolio in 2015 and consequently only a single 'Best Guess' portfolio is examined. For 2020 and 2025 there is a degree of uncertainty surrounding possible future generator retirements and additions. Therefore it is prudent to consider several different potential future generation portfolios.

Case	Description	2020	2025
Base Case	All new conventional generator additions post-2015 are a mix of Gas CCGTs and Gas OCGTs. 40% RoI renewables penetration.	✓	✓
New Flexible Plant	All new conventional generator additions post-2015 are Gas OCGTs. 40% RoI renewables penetration.	✓	✓
New Coal	Moneypoint replaced with new larger more efficient coal units. Less CCGTs and more OCGTs relative to the Base Case. 40% RoI renewables penetration.	✗	✓
High Renewables	Conventional generation assumptions as per Base Case. 53% RoI renewables penetration.	✗	✓
High Storage	New 1500MW pumped storage station. Less CCGTs and more OCGTs relative to the Base Case. 40% RoI renewables penetration.	✗	✓

Table 1.1 All-Island generation portfolios considered in the study.

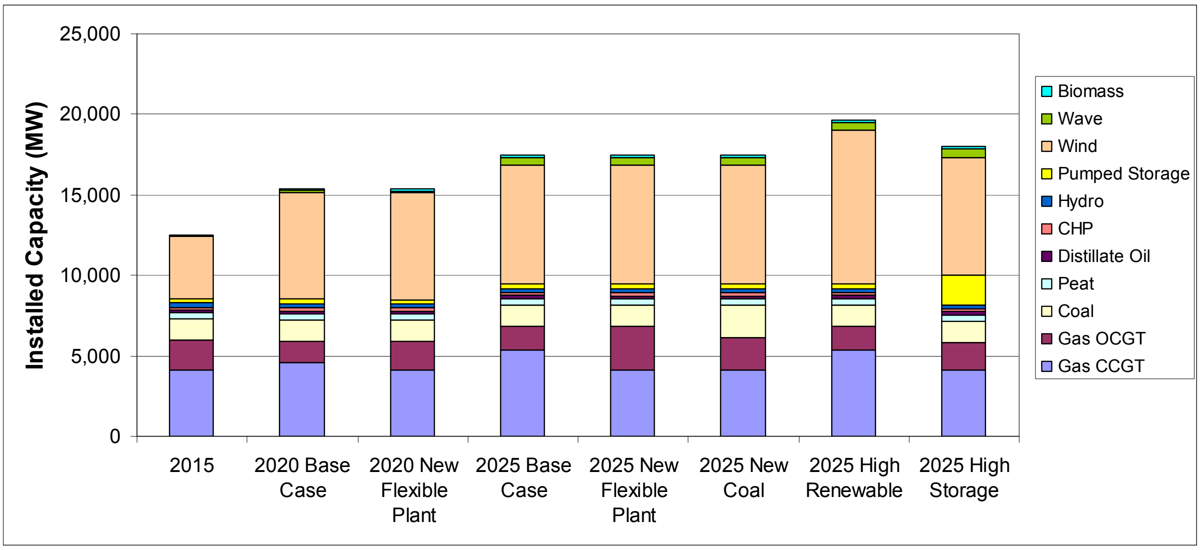

Figure 1.2 Installed capacity by fuel/technology for the All-Island generation portfolios used in the study

1.3.5 Generator Portfolio: Great Britain

Like the All-Island system, the Great Britain system is also modelled at generator level in this study. The Great Britain portfolios for 2015, 2020 and 2025 were provided by Ventyx, a leading business solutions provider to the global energy and utilities industry. A single Great Britain portfolio was provided for each of the three study years. A summary of the forecasted installed capacity mix for Great Britain in 2015, 2020 and 2025 is shown in Figure 1.3.

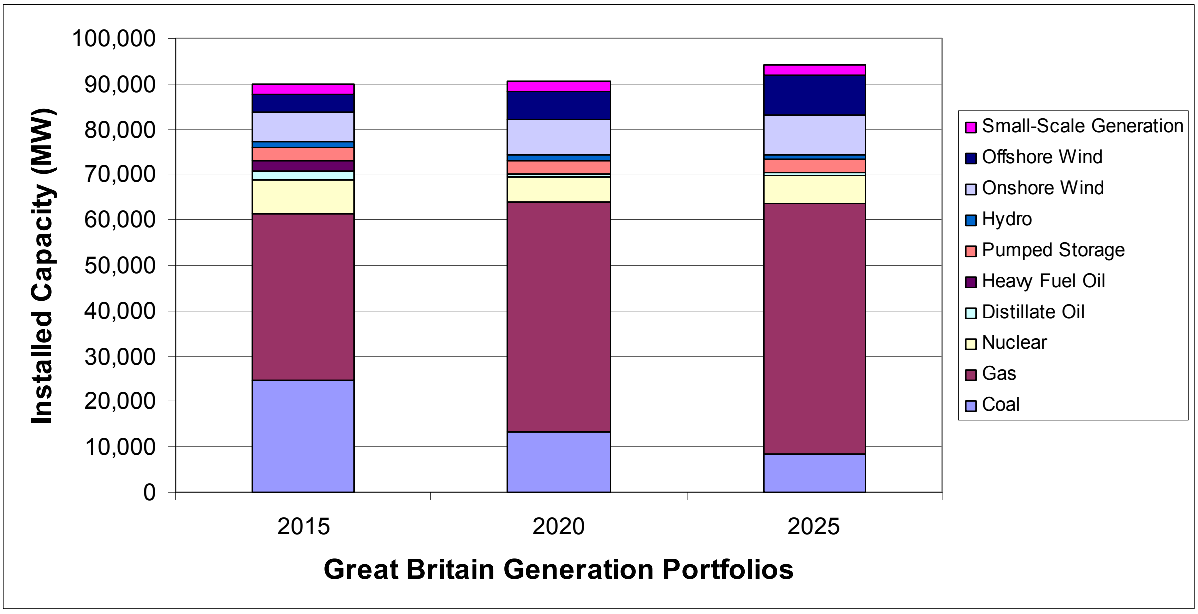

Figure 1.3 Installed capacity by fuel type for the Great Britain generation portfolios considered in the study.

1.3.6 France

The French generation market is characterised by considerable excess generation capacity, primarily nuclear generation, but also hydro and an increasing amount of renewable generation. The French electricity grid is heavily interconnected with surrounding countries. It is thus essential to consider France not just in isolation but as part of a wider European context.

Consequently, modelling France at generator level as per the island of Ireland and Great Britain would not produce sufficiently robust results unless other countries in the region were also modelled. As a result, for this report it was decided to model France using forecasted hourly short run marginal cost price profiles provided by Ventyx, based on their Northwest Europe Energy Market Outlook Autumn 2008 report. Short run marginal cost price profiles were used (as opposed to market clearing price profiles which are higher to cover generators' fixed and financing costs), to ensure compatibility with the island of Ireland and Great Britain modelling methodology. However, this approach is less accurate due to the static nature of the price profiles and it is more difficult to validate the results.

1.3.7 Fuel and Carbon Prices

For the All-Island and Great Britain systems, the fuel and carbon prices employed are critical to the decision as to which units are committed and dispatched, with a consequent impact on both overall system production costs as well as interconnector flows with neighbouring systems.

A number of screening studies were performed to develop the fuel/carbon price scenarios to be employed in the analysis. It was found that increasing or decreasing all of the fuel prices had minimal impact on interconnector flows, because all of the systems are impacted in a similar manner. However, the screening studies showed that changing the price differential between gas and coal had a significant impact on interconnector flows. Hence, two distinct scenarios were studied: 'Base Case' and 'High Coal Price', as outlined in Table 1.2.

Fuel Type	Base Case 2020 €cents/net GJ	High Coal Price 2020 €cents/net GJ
Gas	702.5	732.4
Coal	212.0	337.9
Low Sulphur Fuel Oil	640.2	643.1
Distillate Oil	1206.7	1183.6
Peat	318.0	318.0

Table 1.2 Fuel price assumptions for Ireland and Northern Ireland.

These fuel prices are exclusive of the cost of Carbon. The assumptions on Carbon price are detailed in Table 1.3. The modelling tool factors in the cost of CO_2 emissions when committing and dispatching plant.

Year	€/tonne of CO_2
2015	36.8
2020	41.6
2025	42.7

Table 1.3 Carbon price assumptions

Ireland and Northern Ireland are modelled using the same fuel price assumptions. Great Britain prices differ slightly due to different transport costs built into the fuel price forecasts. The hourly price profiles for each study year used to model France were calculated using the same fuel price assumptions and therefore the price profiles match the two fuel price scenarios.

1.4 ASSESSMENT METHODOLOGY

This study models interconnection by presuming interconnector flow when it is profitable for it to occur i.e. when there are price differences between both ends of the interconnector. In this study, we do not model taxation effects, market support mechanisms or currency arbitrage opportunities. There are four possible mechanisms for price differentials:

- different plant portfolios at each end of the interconnector;
- non-correlated generator outages;
- different wind generation profiles in each country;
- difference in load patterns (particularly on separate holidays).

There are costs associated with using the interconnector, such as system operator charges, power losses on the interconnector, and network losses. Therefore, the price difference must exceed a hurdle level before profitable trading can take place. This has been taken into account in our modelling.

In the following sections, we identify the benefits of interconnection in a number of ways. Each benefit is not always exclusive to the others and we discuss here how they might be considered together.

1) Fuel saving.
   With interconnection, the most efficient generator across both systems is brought on to meet demand resulting in a more efficient dispatch. This is a real saving but it can be difficult to ascribe the saving to particular parties. As the carbon price affects the merit-order, emissions of CO_2 will tend to decrease with interconnection.

2) Changes in marginal prices
   Changes in marginal prices would be expected to drive market prices.

3) Reduction in wind curtailment
   Interconnection reduces wind curtailment as it provides a means of exporting when there is an excess of wind generation. This is a real saving and it would point to the exporting country gaining additional income as long as it is not exporting at negative prices. It may be that the saving could be higher depending on renewable market support mechanisms.

4) Capacity benefit
   An interconnected larger power system needs less generation capacity to maintain security of supply than the total of two power systems require individually.

1.5 RESULTS OF SYSTEM SIMULATION STUDIES

1.5.1 Production cost savings

There are various stakeholders affected by interconnection. Figure 1.4 shows five parties affected by interconnection between AI and GB:

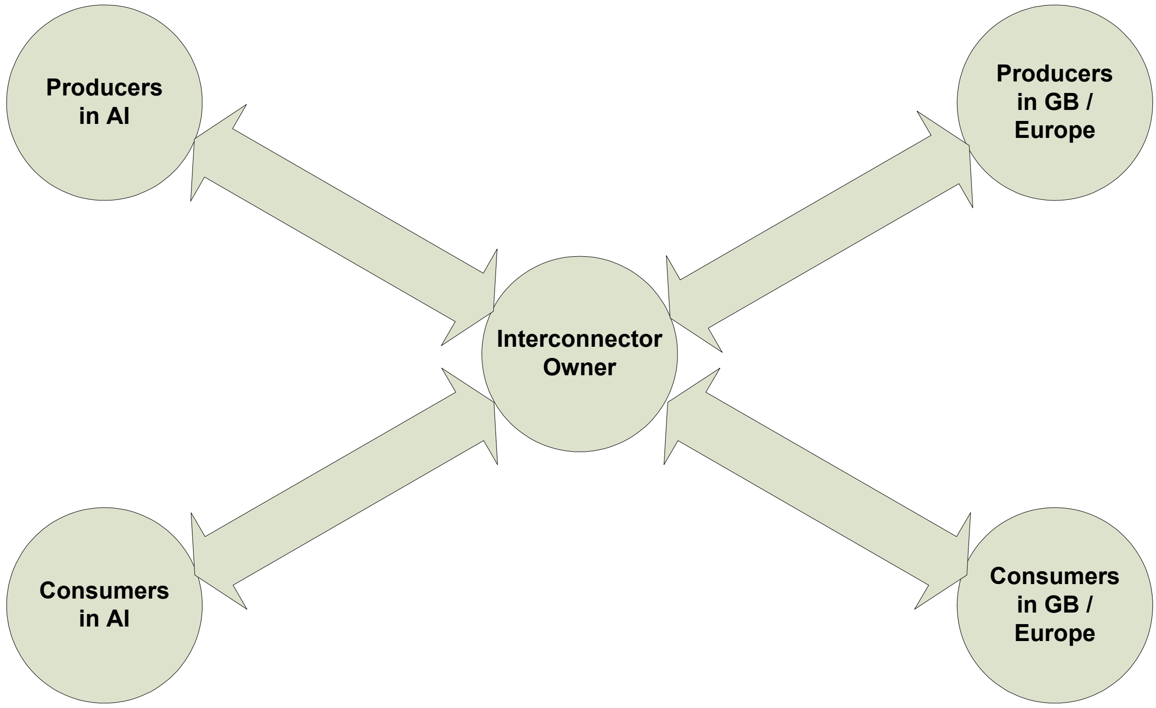

Figure 1.4 Parties affected by interconnection between AI and GB.

The production cost savings that are evaluated in this report would be shared between the parties shown in Figure 1.4; savings are not apportioned between the parties.

Analysis shows that additional interconnection between the island of Ireland and Great Britain results in lower overall production costs i.e. less fuel is used. These savings are shown for 2025 in Figure 1.5.

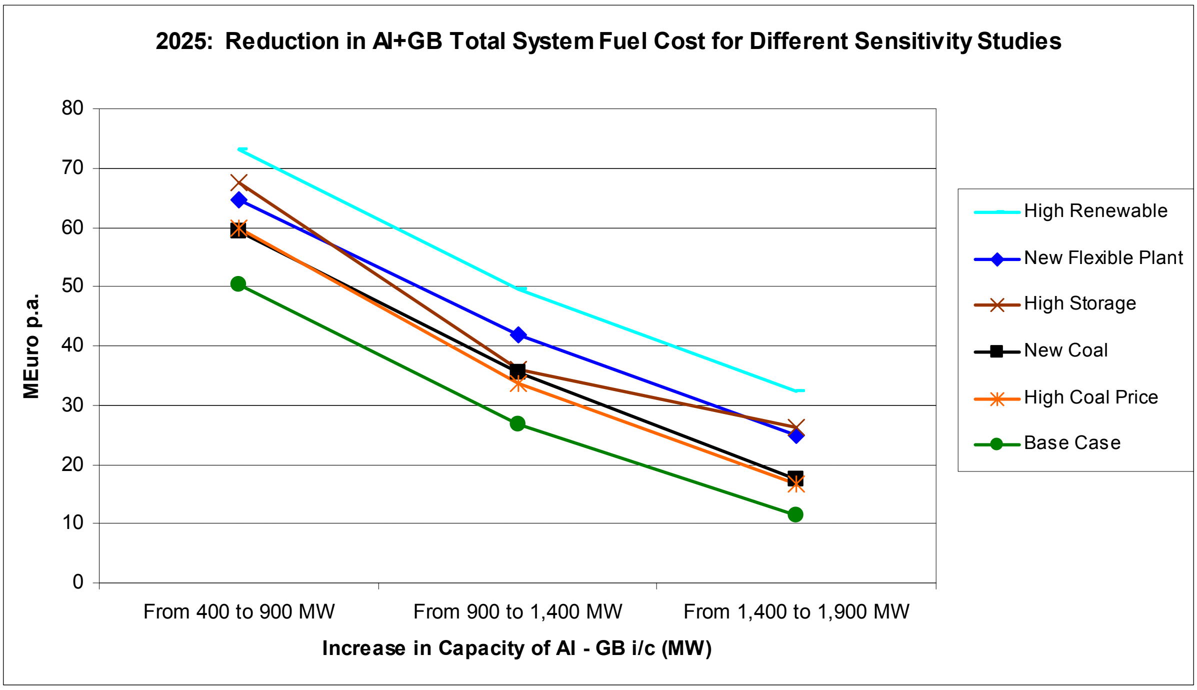

Figure 1.5 Production Cost Savings in 2025 for additional interconnection between the island of Ireland and Great Britain for different generation portfolios.

The quantity of saving varies depending on the amount of interconnection. The most benefit comes from the first additional interconnector and the benefit decreases with additional interconnection. Hence, the East-West Interconnector is forecast to bring production cost savings in the range €50-75 million in 2025. An additional 500MW interconnector would bring production cost savings in the range €25-50 million.

Plant portfolio also influences the amount saved. The Base Case scenario, with a largely similar plant portfolio to now, has the least amount of saving. The High Renewables generation portfolio, with renewable generation contributing 53% of energy, results in the greatest savings from additional interconnection.

1.5.2 Impact on Marginal Prices

For smaller amounts of interconnection, additional interconnection results in marginal prices on the island of Ireland being reduced. For Great Britain, prices actually rise though the increase is small. However, as the number of interconnectors is increased, there are a range of outcomes depending on the generation portfolio and the study year. These studies show that the East-West Interconnector will reduce marginal prices on the island Ireland. With more interconnection the picture is mixed and it is difficult to draw a conclusion. Figure 1.6 shows the load weighted average marginal price for the island of Ireland and Great Britain for the Base Case generation portfolio in 2015.

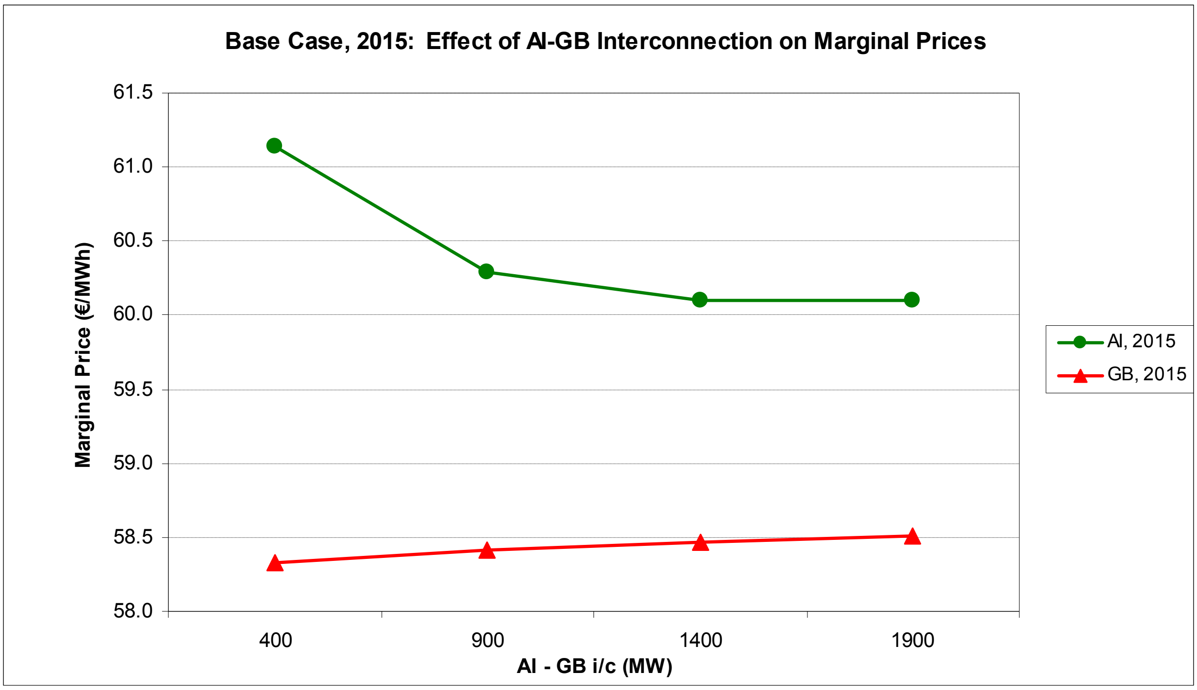

Figure 1.6 Effect of additional interconnection on marginal prices

1.5.3 Reducing Wind Curtailment

Figure 1.7 shows the level of wind curtailment with increasing interconnection for the All-Island system in 2025. As can be seen, additional interconnection reduces wind curtailment across all scenarios. The production cost approach will correctly incorporate the fuel savings from reducing wind curtailment. The full saving may exceed this, depending on support measures for renewables. It would appear that a substantial proportion of the production cost savings derive from reducing wind curtailment on the island of Ireland.

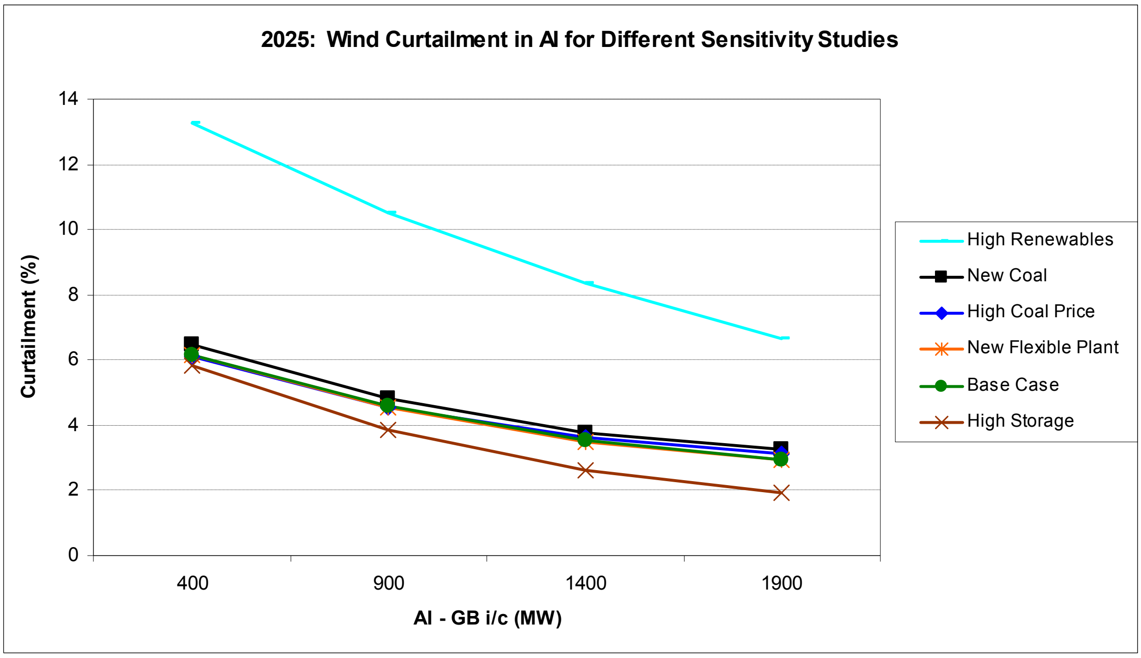

Figure 1.7 Wind Curtailment with increasing interconnection

1.6 RESULTS OF CAPACITY ADEQUACY STUDIES

With the ability to import power when required, an interconnector can provide capacity similar to a generator. We have performed detailed capacity adequacy studies for Ireland and Great Britain in 2020. Figure 1.8 shows the results of these studies. The results show that there are substantial capacity benefits to the island of Ireland from each additional interconnector: 440MW for a third interconnector and 367MW for a fourth interconnector. This is dependent on efficient market coupling being in place so that power can flow when it is required. For Great Britain there are also capacity benefits but these are substantially less than for the island of Ireland.

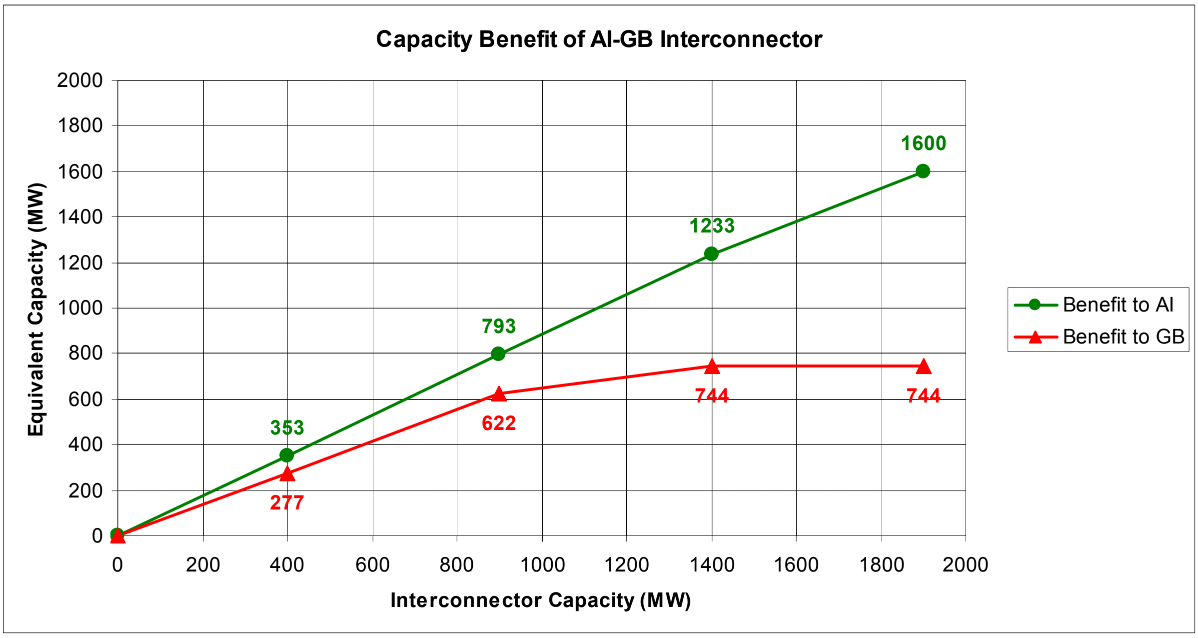

Figure 1.8 Capacity benefit of interconnection

What is the value of this capacity? In the All-Island Single Electricity Market (SEM) there is a Capacity Payment Mechanism (CPM) which values generation capacity at the cost of connecting a least-cost, technically acceptable generator known as the Best New Entrant. This is typically a medium size Open Cycle Gas Turbine (OCGT). This is valued at 80.11 €/(kW x year) for 2010. On this basis, the following capacity benefits would apply:

Increase in Capacity of AI-GB Interconnector	Equivalent Capacity Saving (€M p.a.)		
	AI	GB	AI + GB
From 400MW to 900MW	35	28	63
From 900MW to 1,400MW	35	10	45
From 1,400MW to 1,900MW	29	0	29

Table 1.4 Capacity savings from AI-GB interconnector.

To realise the full capacity benefits for four interconnectors to Great Britain would mean placing 1600MW capacity dependence on these interconnectors. We may not want to put this much reliance on electricity imports as a matter of policy. A more conservative approach would be to place a lower reliance on interconnector capacity, e.g. 75% or 50%.

1.7 COMBINED CAPACITY BENEFITS AND PRODUCTION COST SAVINGS

Two categories of benefit were quantified: reduction in production costs and capacity benefits. While there are other potential benefits such as provision of services and greater competition, we do not consider them here.

Production costs in this report comprise fuel costs and CO_2 costs. Production cost savings arise because the more efficient generators can be used to meet demand on both interconnected grids up to the capacity of the interconnection. There are substantial production cost savings for some of the scenarios studied. For example, in 2020, an additional 500MW interconnector between the island of Ireland and Great Britain would bring production cost savings in the range €25 - €50 million.

Regarding capacity benefits, interconnection was estimated to displace about 88% of best-new-entrant OCGT plant in the AI system, although this ratio decreased slightly beyond 1400MW of interconnection. Applying the same methodology to the Great Britain system, the benefit was approximately 69% of OGCT plant up to 900MW of interconnection, saturating thereafter until no benefit is obtained.

Overall benefits were calculated by combining reduction in production costs and capacity benefits. This was carried out for various scenarios, number of interconnectors, and years.

As outlined in section 1.3.1 a 500MW interconnector between Ireland and Great Britain would cost in the range of **€36 - €43m annualised.**

Figure 1.9 shows combined production cost savings and capacity benefit (both 100%) for AI-GB interconnection. The benefits exceed the costs for all scenarios up to 1400MW, and some scenarios up to 1900MW.

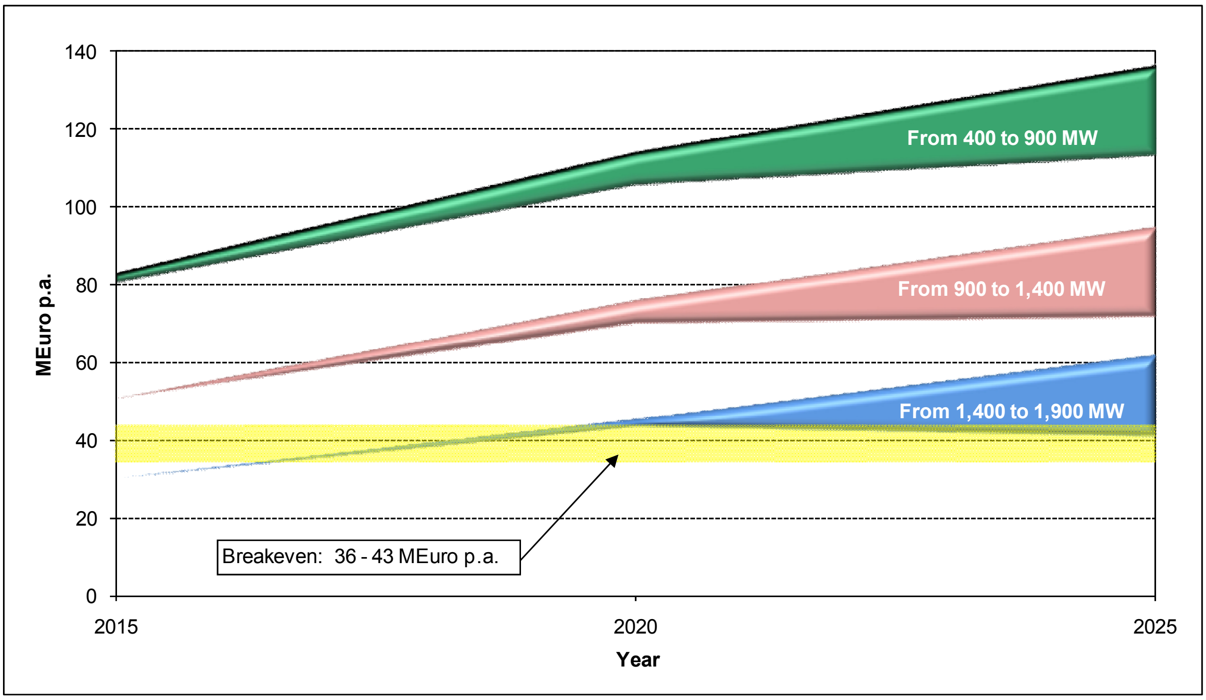

Figure 1.9 Combined production cost savings and capacity benefit for AI - GB interconnection.

Based on Figure 1.9, it can be seen that, in general, benefits increase over time from 2015 out to 2025.

There is limited benefit from an additional interconnector, aside from the East-West interconnector, up to 2015.

There is an economic case for a third interconnector to Great Britain by 2020.

A fourth interconnector to Great Britain is economically justified post-2020 for some scenarios such as High Renewables.

Table 1.5 examines the net benefits of interconnection based on the following combinations:

- 100% or 80% of the savings in production costs are realised.
- 100%, 75% or 50% of the maximum capacity benefits to AI and GB are assumed.

Change in Interconnector Capacity	Production Cost Savings	Capacity Benefits	Net Benefits (€M p.a.)		
	% of AI-GB total	% of AI-GB total	2015	2020	2025
From 400 to 900 MW	100%	100%	42.4	70.4	85.1
		75%	26.7	54.7	69.4
		50%	10.9	38.9	53.7
	80%	100%	38.6	61.0	72.8
		75%	22.9	45.3	57.1
		50%	7.1	29.5	41.3
From 900 to 1,400 MW	100%	100%	11.5	33.5	43.7
		75%	0.3	22.3	32.5
		50%	-11.0	11.0	21.2
	80%	100%	10.3	27.9	36.1
		75%	-0.9	16.7	24.8
		50%	-12.2	5.4	13.6
From 1,400 to 1,900 MW	100%	100%	-9.1	4.9	11.8
		75%	-16.5	-2.5	4.5
		50%	-23.8	-9.8	-2.9
	80%	100%	-9.3	1.9	7.4
		75%	-16.7	-5.5	0.1
		50%	-24.0	-12.8	-7.3

Table 1.5 Net Benefits (€M p.a.) of AI-GB Interconnection to the AI-GB System

Cells with a white background indicate a positive net benefit, cells with a grey background show results within the breakeven zone, while cells with a pink background indicate a negative net benefit.

The East-West Interconnector (i.e. increasing interconnection from 400MW to 900MW) shows a positive net benefit in all combinations.

There is an economic case for a third interconnector (from 900MW to 1400MW) by 2020.

A fourth interconnector to Great Britain is not economically justified up to 2020, however some scenarios show a net benefit in 2025.

1.8 IRELAND-FRANCE INTERCONNECTION

A 500MW and 2 x 500MW interconnection between the island of Ireland and France was modelled in 2015, 2020, and 2025. In all cases, the interconnection between the island of Ireland and Great Britain was assumed to be 900MW.

This study was intended to model flows based on diversity between the two systems. The French system is dominated by nuclear plant, which comprises just under 60% of the total installed capacity. France is interconnected with Belgium, Germany, Switzerland, Great Britain, Spain and Italy. The ratio of exports from France to imports to France in recent years is about 3:1.

Due to the large number of interconnections between France and its neighbours, it was considered difficult to model the French system to the same level of detail as the All-Island and Great Britain systems. Instead, hourly short-run marginal price profiles for France were obtained from Ventyx for each of the three study years, and the two fuel price scenarios. These price profiles were input into the model to determine the flows between France and the island of Ireland.

This sensitivity study indicated high capacity factor for the Ireland-France interconnectors, and reduction in production costs which is shown in Table 1.6.

Savings (€M p.a.)	2015	2020	2025
AI - FR i/c from 0MW to 500MW	38	56	63
AI - FR i/c: from 500MW to 1,000MW	27	37	37

Table 1.6 Production cost savings for 500MW and 1000MW interconnection between the island of Ireland and France

Regarding capacity benefits, a reasonable assumption is to use the same results obtained when examining the AI-GB system. On this basis, a 500MW interconnector (up to 1,000MW of interconnection) would have a capacity value of €35m p.a. to the AI system, and €28m p.a. to the French system, giving a total value of €63m p.a.

Examining the system simulation results at a more detailed level showed factors which are difficult to explain. The problems could be due to the French system being modelled in a less thorough manner than the All-Island system. Without a detailed generation model for France, it is not possible to validate the results. Accordingly, these results need to be corroborated by more detailed modelling. This we intend to carry out and, if there is a significant change in the results, then we will publish an addendum to this report.

1.9 CONCLUSIONS

The analysis reinforces the very strong economic case for the planned East-West Interconnector for all years studied (2015, 2020 and 2025). A further (third) 500MW interconnector between AI and GB is economically attractive in 2020, and more so in 2025. A fourth 500MW interconnector between AI and GB is not economically feasible until 2025; even then, only some scenarios are feasible, such as High Renewables.

A 500MW and 2 x 500MW interconnection between AI and France was modelled in 2015, 2020, and 2025. These studies indicated high capacity factor for the Ireland-France interconnector, and corresponding reductions in production cost. However, these results need to be corroborated by more detailed modelling before any recommendations could be made on Ireland-France interconnection.

In general, interconnection becomes more economically attractive further out in time. A High Renewables scenario improves the case for interconnection. The incremental benefits of interconnection decrease with each subsequent interconnector.

The production cost savings that are evaluated in this report are the total benefits to both sides; savings are not apportioned between the parties. EirGrid recommends that there is engagement with responsible agencies on the island of Ireland and abroad to create a framework for funding of new interconnectors.

The following next steps follow on from this report:

- Produce a work programme to develop detailed costings and investigate technical feasibility of different interconnector options and routes, that can be used as an input to investment decisions. In parallel with this, it is necessary to develop arrangements for funding of interconnectors.
- Investigate increasing the export capability of Moyle Interconnector. In terms of capability, the Moyle Interconnector can import 450MW from Scotland in winter and 400MW in summer. However, the Moyle Interconnector is limited by contractual arrangements to an export capacity to Scotland of 80MW. There is economic benefit from increasing the export capability from 80MW to 400MW. This removal of this restriction is currently under review by Moyle Interconnector Ltd, the owner of the Moyle Interconnector.
- Carry out further studies on the economic benefit of Ireland–France interconnection. There is uncertainty about the validity of the modelling results for Ireland–France interconnection. More detailed modelling of the French power system is needed to vouch for the results obtained. We will have to take into account the fact that France is highly interconnected already. EirGrid intends to do this more detailed modelling of France and its connected systems. If there is a significant change in the results, then we will publish an addendum to this report.
- Market issues are significant. The benefits identified in this report can only accrue if there is efficient market coupling between the island of Ireland, Great Britain and France. EirGrid welcomes the recent consultation paper issued by the Regulatory Authorities 'SEM Regional Integration'. This is directly addressed at how to best leverage the interconnectors to reduce costs and lower prices. EirGrid, as system operator and market operator, are committed to working pro-actively with the Regulatory Authorities and all stakeholders to deliver efficient market arrangements that meet the needs of stakeholders and comply with EU directives.
- Investigate offshore grids. In the next 20 years there are likely to be substantial off-shore wind farms developed in the Irish Sea: both on the Irish coast and the English-Wales-Scotland coasts. EirGrid is publishing an Offshore Grid Strategy to set out a roadmap for the development of off-shore grids. The aim of the strategy is not just to connect off-shore wind farms but also to coordinate these connections with transmission grid developments and interconnector developments. The need to connect the off-shore wind farms presents an opportunity to coordinate with interconnector developments and realise more efficient outcomes.

2 INTRODUCTION

Interconnection between Ireland's electricity grid and other grids has the potential to deliver numerous benefits to Ireland. In particular, interconnection enhances security of supply, promotes competition in the electricity sector and facilitates the expansion of renewable energy generation. The 400MW Moyle Interconnector, which connects the electricity grids of Northern Ireland and Great Britain, went into commercial operation in 2002. In the Republic of Ireland, EirGrid is currently developing the 500MW East-West Interconnector to Great Britain with a scheduled completion date of 2012. Hence, upon completion of the East-West Interconnector, the island of Ireland will have 900MW of interconnection with Great Britain.

In March 2007 the government published a White Paper entitled "Delivering A Sustainable Energy Future For Ireland". The White Paper states that EirGrid will be requested to analyse the feasibility of potential further interconnection with Great Britain (i.e. additional to the planned East-West Interconnector and the Moyle Interconnector) and/or new interconnection with continental Europe. In order to deliver the requested feasibility study, the Generation Analysis team in EirGrid established a project called 'Additional Interconnection – A Feasibility Study'.

The aim of this project is to analyse the feasibility and/or requirement for additional interconnection from an economic perspective. It is not within the scope of this project to assess the capability of the Irish grid to accept further imports from and deliver exports to other transmission systems, additional to imports and exports across the planned East-West Interconnector and the Moyle Interconnector.

The project deliverable is this report outlining the results of the feasibility study. The feasibility study will:

- Focus on three particular study years – 2015, 2020 and 2025.
- Consider several different potential Irish plant portfolios for each study year.
- Assess the economic impact of further interconnection through analysis of system production costs and the capacity benefit to the Irish power system.
- Assess the impact of further interconnection on the Irish system marginal price.
- Examine the level of utilisation of potential additional interconnectors.

3 MODELLING METHODOLOGY

3.1 Introduction

This chapter provides an overview of the modelling methodology employed to assess the case for additional interconnection to Great Britain or France.

The current position in relation to interconnection between Ireland, Great Britain and Northwest Europe is outlined and the distinct market structures currently in place in the different regions are described.

The methodology of production cost modelling is utilised to conduct the studies for this report. The rationale for utilising production cost modelling is presented along with a detailed description of production cost modelling. A description of the modelling tools employed is also provided.

The Republic of Ireland, Northern Ireland and Great Britain systems are modelled at individual generator level in these studies. The rationale for modelling in such a high level of detail is provided.

The base case for interconnection between Great Britain and Northwest Europe includes links to France and the Netherlands. For this report it was decided to model France and the Netherlands using forecasted hourly short run marginal cost price profiles. The rationale for modelling France and the Netherlands in this manner is presented.

Finally, an overview of the range of scenarios examined in this report is presented.

3.2 Overview of the Modelling Methodology

The Moyle Interconnector, which connects the electricity grids of Northern Ireland and Great Britain, went into commercial operation in 2002. It has a capacity of 500MW and currently is capable of importing 450MW in winter and 400MW in summer from Scotland. However, the Moyle Interconnector is limited by contractual arrangements to an export capacity to Scotland of 80MW. This restriction is being reviewed at the moment, and we have assumed the export capability is increased to 400MW for our study. In the Republic of Ireland, Eirgrid is currently developing the 500MW High Voltage Direct Current (HVDC) East-West Interconnector to Great Britain with a scheduled completion date of 2012. Hence, upon completion of the East-West Interconnector, the island of Ireland will have 900MW of interconnection with Great Britain.

Great Britain is interconnected to France via a 2,000MW HVDC link between the British and French transmission systems with ownership shared between National Grid Company (NGC), the TSO in Great Britain, and Réseau de Transport d'Electricité (RTE), the TSO in France. In addition, NGC and TenneT (the Dutch TSO) are developing a 1,000MW interconnector between Great Britain and the Netherlands. The BritNed interconnector is expected to be constructed and operational by early 2011. Therefore, the base case scenario for analysing the case for additional interconnection between the island of Ireland and other transmission systems includes 900MW of interconnection between the island of Ireland and Great Britain and 2,000MW and 1,000MW of interconnection between Great Britain and France and Great Britain and the Netherlands respectively. Given the distances and costs involved, any further interconnection between the island of Ireland and other transmission systems above and beyond the current 900MW capacity is likely to be with Great Britain or France.

Given the existing interconnected nature of the systems, assessing the impact of any further interconnection on the Irish system requires an integrated model of the All-Island, Great Britain, France and the Netherlands electricity systems. However, the market structures currently in place in the four systems are markedly different from one another.

The Single Electricity Market (SEM), which commenced full operation on 1st November 2007, is the wholesale electricity market operating in the Republic of Ireland and Northern Ireland. It is a centralised gross mandatory pool market operating with dual currencies and in multiple jurisdictions and, as such, it represents the first market of its kind in the world. Electricity is bought and sold through the pool under a market clearing mechanism. Under the pool arrangements, all generators receive and all suppliers pay the same energy component of electricity price in a trading period; the System Marginal Price (SMP). Generators receive the SMP for their scheduled dispatch quantities (the generators' physical hourly commitment and dispatch are determined based on their short run marginal costs), capacity payments based on a measure of their availability, and constraint payments for differences between the actual dispatch schedule and the market schedule (as a result of system constraints). Suppliers purchasing energy from the pool pay the SMP for each trading period in addition to capacity costs and system charges. The SEM market rules are described in the Trading and Settlement Code which can be viewed at http://www.allislandmarket.com/MarketRules/.

On 1st April 2005, the British Electricity Trading and Transmission Arrangements (BETTA) introduced a single wholesale electricity market for Great Britain with a single transmission system operator (National Grid Company, NGC) independent of generation and supply. Unlike the SEM, BETTA is based on bilateral trading between generators, suppliers, traders and customers across a series of markets operating on a rolling half-hourly basis. In effect, BETTA operates like other commodity markets, whilst making provision for the electricity system to be kept in physical balance at all times so as to maintain security and quality of supply. Under BETTA, the vast bulk of electricity is traded in forward, futures, and short-term markets (power exchanges) through bilateral contracts. Only small volumes are subject to arrangements in the central Balancing Mechanism, used by NGC to ensure that supply and demand balance in real-time.

The French electricity market is dominated by a single player, Electricité de France (EDF). EDF dominates the generation sector with approximately 90% of total installed production capacity. The other two main generators are Electrabel-Suez and Endesa which hold approximately 5% of installed capacity between them. EDF is a fully integrated utility - it owns the transmission system operator and is also the dominant supply company. The French generation market is characterised by considerable excess generation capacity, primarily nuclear generation (just under 60% of total installed capacity) but also hydro and an increasing amount of renewable generation. The French electricity market is heavily interconnected with the Belgian, German, Swiss and British markets, and to a lesser extent, with the Spanish and Italian markets. However, trading with Germany represents the bulk of electricity exports and imports. France does have a traded market and an imbalance market but with the bulk of the French power transactions being bilateral, neither market is considered fully representative of French market fundamentals.

The Dutch electricity market is dominated by Electrabel, E.On Benelux, Essent and Nuon who together own approximately 65% of the installed capacity in the Netherlands. Generation capacity in the Netherlands is dominated by gas-fired generation. The remaining generation market is primarily Combined Heat and Power (CHP) and decentralised production, with increasing penetration of wind and other renewables. The Netherlands is well connected with neighbouring countries; Belgium (for electricity transiting from France), Germany and Norway (NorNed came on line in May 2008. This is a 700MW DC under-sea link which is a joint project between TenneT and Stattnet, the Norwegian TSO) and, as already stated, has a planned 1,000MW link to Great Britain. APX operate an active traded market in the Netherlands for short term electricity trading. Wholesale electricity prices are generally higher in the Netherlands than in France and Germany mainly due to the presence of large amounts of relatively cheap nuclear and coal generation respectively in those countries.

Accurately modelling the diverse market structures currently in place in Ireland, Great Britain, France and the Netherlands and capturing the dynamic interaction between them (in terms of interconnector flows) would require a modelling sophistication beyond any currently available modelling tool. Also, given the timeframe considered in this study (out to 2025), it is reasonable to assume that significant changes in market structures are likely to occur during the period studied, particularly with the EU very much in favour of increased market integration and coupling. Consequently, it was decided to utilise the methodology of production cost modelling to conduct the studies for this report.

3.3 Production Cost Modelling

In general terms, production cost models utilise optimisation algorithms with the objective of minimising the cost of generating power to meet demand in a region while satisfying operational, security and environmental constraints. The cost minimised within a production cost model is the fuel and CO_2 cost (variable operation and maintenance costs can also be taken into account but are not considered in this study). Wind and wave powered generation have essentially zero cost but are not dispatchable. Hydro generation also has zero cost but is energy limited. Chronological production cost models optimise generator commitment and dispatch scheduling for every hour of a study period (typically one year duration). Production cost models require:

- Accurate specification of individual generator capabilities including capacity, start-up energy, annual forced outage rate, annual scheduled outage duration, ability to provide reserve, emissions rate and heat rates (fuel requirement per unit of generation)
- Specification of the hourly demand profile for the region.
- Specification of the fuel price for each type of fuel.
- Specification of the transmission network (only required for certain studies where transmission constraint information is a desired output).
- Specification of the constraints:
    - System security constraints such as the requirement for reserve.
    - Generator operational constraints such as maximum and minimum operational levels, ramp rates, minimum runtimes and downtimes etc.
    - Environmental constraints such as the cost of CO_2.

The production cost modelling tool employed in this study was PROMOD. PROMOD's features are described in Section 3.6.

3.4 Ireland and Great Britain Model

The Republic of Ireland, Northern Ireland and Great Britain systems are modelled at generator level i.e. every single conventional generator is modelled in detail. Characteristics such as heat rates, ramp rates, minimum runtime and downtime, start-up energy, ability to provide reserve, annual forced outage rate, annual scheduled outage duration and emissions rate of each individual generator have to be specified. Wind and wave powered generation are modelled using a separate hourly power series for the Republic of Ireland, Northern Ireland and Great Britain (more detail on the modelling of wind powered generation is provided in Section 4.5).

In this study, Ireland and Great Britain are treated as a single system in the production cost model for the purposes of producing an optimal minimum cost commitment and dispatch. The Uplift and Capacity Payment mechanisms present in the SEM and the bidding strategies inherent in BETTA are not modelled. Instead, generators in both markets are dispatched based on their short run marginal costs (which include the costs of fuel and CO_2 emissions). It is assumed in this study that any potential future market structures in place in Ireland and Great Britain will be efficient and appropriately reflect the underlying short run marginal costs in the commitment and dispatch decisions.

<u>Transmission Constraints</u>

In the SEM, there are currently limitations on power flows between the Republic of Ireland and Northern Ireland (although this constraint will be alleviated when the new North-South Interconnector is completed in 2012) as well as more localised transmission congestion. Similarly, in Great Britain there is significant transmission congestion between Scotland and England/Wales. However, in this study transmission constraints within each market area are not modelled. The only transmission constraints modelled relate to the finite interconnection capacity linking market areas.

Transmission congestion can be relieved through transmission additions and uprates and/or generator additions and upgrades. It is implicit in the analysis performed for this report that such actions are undertaken on an economic basis over the period of the study.

Interconnector Modelling

In this study, it is assumed that interconnection operates as a perfect arbitrageur. Under this assumption, power flows between market areas (from the low price area to the high price area) whenever there is a price differential between the two areas. Power losses on the interconnectors are not explicitly modelled; however a “hurdle rate” of 3 €/MWh is assumed between interconnected systems (price differentials less than this will not produce a flow). The amount of power that flows is limited by the interconnection capacity between the two areas. It should be noted that in practice, this optimal ‘perfect’ operation of the interconnector is unlikely to occur. It is essential that any potential future market structures as well as interconnector governance and regulatory regimes are designed to enable the most efficient and effective interconnection operation possible.

Rationale for Great Britain Model

The rationale for modelling Great Britain in such a high level of detail is based in part on the enormous anticipated growth in the level of installed wind powered generation capacity in both Ireland and Great Britain over the coming years. While differences in the conventional plant portfolios in the two countries will create arbitrage opportunities between the two markets, those hours when wind is blowing strongly in one market and not so strongly in the other will serve to amplify price differentials resulting in increased flows on the interconnectors. With wind powered generation expected to constitute a far higher percentage of the overall installed system capacity in Ireland than Great Britain, it is likely that periods with high wind in Ireland and low wind in Great Britain would have a greater impact on price differentials and resulting interconnector flows than the opposing scenario with low wind in Ireland and high wind in Great Britain. Clearly then, the wind profiles employed for Ireland and Great Britain, and more specifically, the level of correlation between these profiles, are very important. Another advantage of modelling Great Britain in a high level of detail is that it makes it easier to validate the results. Finally, it also enables potential follow-on studies examining the impact of different portfolios in Great Britain.

Figure 3.1 shows the correlation between the hourly wind powered generation output as a percentage of capacity in Ireland and Great Britain in 2007. While a relationship does exist between the hourly levels of wind powered generation output it is not a strong one, as indicated by the relatively low level of correlation of 0.46. Clearly, there are many hours when the wind generation output in both markets is similar and correlated. In addition, there are also relatively few periods when wind generation in Ireland is extremely high and wind generation in Great Britain is extremely low and vice versa. However, the low level of correlation indicates that there are many periods when higher wind generation in one market and lower wind generation in the other market will create arbitrage opportunities and consequently will affect flows on the interconnectors.

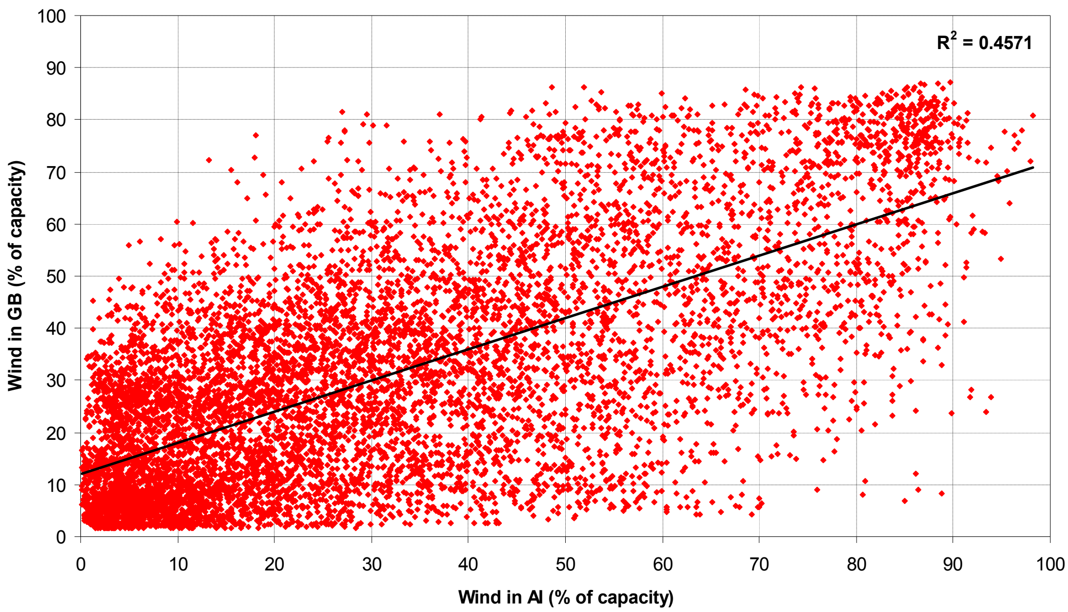

Figure 3.1 Correlation between the hourly wind powered generation output as a percentage of capacity in Ireland and Great Britain in 2007

3.5 France and Netherlands Model

Both France and the Netherlands are highly interconnected with surrounding countries. It is therefore essential to consider France and the Netherlands not just in isolation but as part of a wider European context. Consequently, modelling France and the Netherlands at generator level as per Ireland and Great Britain would not produce sufficiently robust results unless other countries in the region were also modelled.

As a result, for this report it was decided to model France and the Netherlands using forecasted hourly short run marginal cost price profiles. Short run marginal cost price profiles are employed as opposed to market clearing price profiles (which are higher to cover generators' fixed and financing costs) to ensure compatibility with the Ireland and Great Britain modelling methodology.

The price profiles were provided by Ventyx, a leading business solutions provider to the global energy and utilities industry. In producing the price profiles, Ventyx explicitly modelled the following countries as being part of Northwest Europe: France, Germany, Netherlands, Belgium, Luxembourg, Austria and Switzerland. These countries within the Ventyx Northwest European topology were modelled simultaneously and the internal flows determined economically. The exchanges with Northwest Europe and its neighbouring countries (such as Great Britain, Spain, Italy, Poland etc.) were modelled using simplified representations of available capacity and/or energy.

The use of price profiles in the model does have a potential drawback relating to the static nature of the price profiles employed. For example, considering a modelling scenario where Ireland and France are interconnected and price differentials drive flows across that interconnector, the System Marginal Price (SMP – in this study the SMP is determined by the short run marginal cost of the marginal unit) in Ireland will change depending on the flow whereas the corresponding SMP in France remains unaffected. However, it is considered that this potential shortcoming in the model has negligible effect on results. This is due to the relative size of the All-Island and French markets. The All-Island energy market is quite small and the commitment/dispatch and SMP are heavily influenced by flows from France. Conversely, the size of the French system allied to large scale interconnection with other markets in continental Europe mean that flows between Ireland and France would have no material impact on the French SMP.

3.6 Modelling Tools

Two computer programs are used in the analysis: CREEP and PROMOD. The former is used to determine the 'adequacy' of the generation system. The latter performs simulations on the operation of the system. Both these programs are now briefly described.

CREEP

The program name is an acronym for Capacity Requirement Evaluation by Exact Probability. CREEP uses an analytical procedure to determine future generation capacity requirements. It is the program used in preparing the annual Generation Adequacy Report published every year by EirGrid.

CREEP requires that the capacity (MW), scheduled outage duration (weeks) and forced outage probability (%) of each generation unit on the system be specified. A demand model must also be specified, comprising the estimated total demand at every hour of the future year to be studied. The program then calculates the Loss of Load Expectation (LOLE) for the year under study for the specified generation plant aggregate and hourly demand profile.

The standard LOLE accepted for generation adequacy on the All-Island system is 8 hours per year. Iteration is often required to adjust the generation plant aggregate until the LOLE is acceptably close to the standard, given the discrete sizes in which generation units are commercially available.

PROMOD

This is an hourly Monte Carlo generation production cost modelling simulation program, used to determine system performance and cost. It is a complex and very powerful tool for power system analysis, with separate commitment and dispatch algorithms.

The Monte Carlo element of the program relates to the treatment of the forced outages of generation units and to the duration of their outages. These outages occur randomly during the year, yet conform to the specified forced outage probability values. The duration of each outage varies randomly about a mean outage time, which is specified in advance. This element of the program adds greatly to the realism of the simulation.

Full technical performance characteristics and operational cost details of each generation unit on the system must be specified. An hourly system demand profile, as in CREEP, is also required. The transmission and distribution systems can also be modelled in detail if desired.

The program output provides complete details of the operation of each generation unit. These are aggregated into system totals. Flows on transmission lines can be monitored and potential constraints on the system can be identified. A wide range of output reports is available, from system summaries to hour by hour information on individual generators.

3.7 Range of Scenarios Assessed

Due to uncertainties in the future, it is prudent to examine the case for additional interconnection for many different scenarios. The different scenarios for which results are presented in Chapter 5 can be broadly divided into the following categories:

- Study years
- Amount of interconnection with Great Britain/France
- Fuel prices
- All-Island generation portfolios

- Conventional generation mix
- Renewable penetration level

4 INPUT ASSUMPTIONS

4.1 Introduction

This chapter provides an overview of the assumptions employed in the development of the models for each study year. The current position in relation to interconnection between Ireland, Great Britain and Northwest Europe is outlined and the approach adopted in adding further interconnection between Ireland and the other systems is presented.

The renewable energy targets set by the Irish Government are described and the required installed wind generation capacities to meet the targets are detailed. The methodology employed for modelling wind powered generation in the studies is then presented and the issue of curtailment is explained.

The All-Island and Great Britain systems are modelled at generator level and therefore the generation portfolio to be employed for each study year must be specified explicitly. Several different potential future generation portfolios for the All-Island system are considered and assessed with respect to their generation adequacy position. A single Great Britain portfolio is considered for each of the study years.

A forecast of future electricity demand is an important input to the studies. The types and sources of demand input data, along with the actual demand forecast utilised in this report are presented.

Finally, the fuel and carbon prices employed in the modelling are critical to the decision as to which generators are committed and dispatched with consequent impact on both overall system production costs as well as interconnector flows with neighbouring systems. The assumptions on fuel and carbon prices employed are presented.

4.2 Study Years

It was decided to assess the case for additional interconnection from an economic perspective for three sample years in the future. Given the development timeframe required for large-scale interconnection projects is in the order of several years, it was considered unlikely that further interconnection could be in place long before 2015. As a result, the earliest year chosen for analysis was 2015. It was felt that five-year intervals between study years would be appropriate to enable reasonably significant changes to occur in terms of generation mix, fuel/carbon prices etc. Hence, 2020 and 2025 were also selected for analysis.

4.3 Interconnection Scenarios

The scheduled completion of the 500MW East-West Interconnector by EirGrid in 2012, allied to the 500MW Moyle Interconnector which has been in commercial operation since 2002, will result in the island of Ireland having 1000MW of interconnection with Great Britain. However, the Moyle Interconnector is limited to 400MW import in summer from Scotland so for this study, we have assumed a total of 900MW of interconnection between the island of Ireland and Great Britain. Great Britain in turn is interconnected to France via a 2,000MW HVDC link. In addition, the 1,000MW BritNed Interconnector between Great Britain and the Netherlands is expected to be operational by early 2011. Therefore, the base case scenario for analysing the case for additional interconnection between the island of Ireland and other transmission systems includes 900MW of interconnection between the island of Ireland and Great Britain and 2,000MW and 1,000MW of interconnection between Great Britain and France and Great Britain and the Netherlands respectively.

Given the distances and costs involved, any further interconnection between the island of Ireland and other transmission systems above and beyond the current 900MW capacity is likely to be with Great Britain and/or France. The approach adopted in this study is to consider 500MW 'blocks' of interconnection between the island of Ireland and France/Great Britain up to a total interconnection capacity of 1,900MW between Ireland and Great Britain and 1000MW between Ireland and France i.e. two new 500MW interconnectors to Great Britain and two new 500MW interconnectors to France. The interconnection scenarios examined in the study are detailed in Table 4.1. These scenarios are examined for the years 2015, 2020 and 2025.

Scenario	Ireland & Great Britain				Ireland & France		Great Britain & France	Great Britain & Netherlands
	400MW	900MW	1400MW	1900MW	500MW	1000MW	2000MW	1000MW
Scenario 1	√						√	√
Scenario 2		√					√	√
Scenario 3			√				√	√
Scenario 4				√			√	√
Scenario 5		√			√		√	√
Scenario 6		√				√	√	√

Table 4.1 Interconnection scenarios examined in the study.

4.4 Renewable Targets

In March 2007 the Government published the White Paper – 'Delivering a Sustainable Energy Future for Ireland'. That paper set out the following action item: 'We will achieve 15% of consumption on a national basis from renewable energy sources by 2010 and 33% by 2020'. In the Carbon Budget of October 2008, the 2020 target was extended from 33% to 40% of RoI gross electricity consumption to be met by renewables. For the purposes of this report, it is assumed that by 2015, sufficient levels of renewable generation are installed such that, if projected linearly forward to 2020, a penetration level of 33% of RoI gross electricity consumption would be achieved. However, by 2020 it is assumed that the higher 40% target is achieved through increased rollout of renewable energy projects in the mid-to-latter stages of the decade. The studies also assume that in 2025, 40% of RoI gross electricity consumption is supplied by renewable generators.

The potential contribution of ocean energy to meeting the targets is captured in the studies with 120MW of wave powered generation assumed to be installed by 2020 rising to 500MW installed capacity by 2025. Large-scale hydro, small-scale hydro and biomass are also expected to contribute appreciably to meeting the challenging 40% target. However, given Ireland's excellent natural wind resources and the relative maturity of wind powered generation technologies, in the studies carried out for this report it is assumed that the renewable penetration levels will be achieved largely through the deployment of additional wind powered generation. Given the demand assumptions described in Section 4.11 and assuming a capacity factor of 31% for future wind powered generation, Table 4.2 details the required installed wind generation capacity to meet the targets.

Year	Wind - Installed Capacity (MW)
2015	2891
2020	5389
2025	5845

Table 4.2 Required installed wind generation capacity to meet targets.

4.5 Wind Modelling

The PROMOD software tool models wind powered generation using an hourly wind power series. EirGrid maintains a database which contains the metered output at 15 minute intervals for every wind powered generator in the Republic of Ireland. By amalgamating the output of all the windfarms which have been in commission for a full calendar year it is possible to build up an annual system wind profile with 8760 hourly values. For this project, 2007 was chosen as the base wind profile year. The historical base wind profile is then used to produce future year wind profiles by scaling to the appropriate installed wind capacity level.

In 2007, the average capacity factor for wind powered generation in the Republic of Ireland was 29.1%. It is generally considered that this was a below average year for wind speeds. In fact, the capacity factor for the three years 2005, 2006 and 2007 averaged 31%. In the future, it is possible that improvements in wind generation technology will enable more power to be captured from the same wind conditions. On the other hand, it is possible that the best sites from a wind regime have been developed already with future developments experiencing less favourable wind regimes. In any case, it was decided to use a capacity factor of 31% for the projected future Republic of Ireland wind profiles. This is accomplished through appropriate scaling of the projected future hourly wind power series.

Hourly wind power series were also used to model wind in Northern Ireland and Great Britain. In the case of Northern Ireland, the output of all the windfarms was amalgamated to build up a 2007 system wind profile. The 2007 capacity factor was 31.9%. This data was provided to EirGrid by the System Operator for Northern Island (SONI). An hourly wind power series for Great Britain in 2007 was provided by Ventyx. As for the Republic of Ireland, these 2007 wind profiles were used to produce future year wind profiles by scaling to the appropriate installed wind capacity levels. For Northern Ireland and Great Britain, the estimated future installed wind capacities were provided by SONI and Ventyx respectively.

4.6 Curtailment

Curtailment refers to the reduction of the output of wind powered generators in order to maintain the operation of a safe, secure and reliable power system. At times when wind generation levels are a high percentage of system demand, it is necessary to curtail output from wind powered generators in order to retain the necessary amount of conventional generation online to provide all the system services required:

- Frequency control
- Provision of Reserve
- Voltage control
- Load following
- Ability to withstand disturbances

At moderate wind penetration levels, curtailment is most likely to occur at times of low system demand i.e. night time and summer time. However, as wind penetration levels increase, curtailment could occur at other times of the day/year.

Interconnection enables excess wind energy to be exported rather than 'spilled', provided of course that the neighbouring system does not also have an excess of wind generation at the same time. The extent to which additional interconnection alleviates the issue of wind curtailment is investigated and the results are presented in Section 4.

Note that the output of wind powered generators may also need to be reduced due to transmission network limitations. The constraining of wind generation for this reason is location-specific and can be significantly reduced by transmission network reinforcements. For the purposes of this study, it is assumed that there are no internal system bottlenecks that could cause wind to be constrained in this manner. As such, the only transmission constraints are the interconnector flow capacities between the distinct systems.

In addition, for the purposes of this study, it is assumed that the output of wind powered generation can be predicted with a high degree of accuracy. This is a slightly optimistic assumption because in real-life there is usually some differential between forecasted and actual wind power. However, the option of assuming little or no forecasting ability was thought to be unrealistic given the current level of research and development activity in the area. The assumption of 'perfect foresight' leads to slightly reduced curtailment levels in comparison to what might be observed in real-life. This is as a result of conventional thermal generation being kept online to ramp up in the event that the wind power output is lower than forecasted.

4.7 Generation Portfolios

As already stated in Section 3.4, the Republic of Ireland, Northern Ireland and Great Britain systems are modelled at generator level and therefore the generation portfolio to be employed for each study year must be specified explicitly. Given the timeframe that the study covers and the degree of uncertainty surrounding possible future plant retirements and additions, it is prudent to consider several different potential future generation portfolios for the All-Island system. In addition, the developed generation portfolios need to be assessed with respect to their generation adequacy position.

4.8 Generation Adequacy

Generation adequacy concerns the capability of the generation capacity to supply the electricity demand on the system. It is assessed by determining the likelihood of there being sufficient generation to meet customer demand, or in other words, by calculating the risk that supply shortages will occur. The potential for supply surpluses or risk of supply shortages is calculated by using statistical techniques to determine the probability that demand will exceed supply given the various planned maintenance requirements of generation units and the probability of forced outages. This assessment is carried out for every half hour of the 2015, 2020 and 2025 study periods for each of the proposed generation portfolios. From these half hourly probabilities, an annual expectation is determined of the number of hours in the year that demand would be expected to exceed supply.

This annual expectation, known as Loss of Load Expectation (LOLE), is compared against a standard or benchmark level in order to assess if the level of risk is acceptable or not. The magnitude of any divergence from standard indicates the scale of the risk. For Ireland the LOLE standard is 8 hours per year with LOLE levels above this indicating higher than acceptable levels of risk.

An important consideration is that the contribution of wind generation capacity to generation adequacy, referred to as the capacity credit of wind, is very different to that of conventional thermal generation due to its inherently variable nature. Analysis based on 2006 wind data established that this capacity credit is reasonably significant at low levels of wind penetration, but the benefit tends towards saturation as wind penetration levels increase, as illustrated in Figure 4.1. This is because there is a significant risk that a single source of failure, (i.e. very low or very high wind speeds across the country), will result in all wind farms producing practically no output for a number of hours, even allowing for geographic diversity. This has been verified by monitoring the output from wind generation, at quarter hourly intervals, over a number of years. In contrast, the forced outage probabilities for all thermal (and hydro) units are assumed to be independent of each other. Therefore, the probability of all thermal and/or hydro units failing simultaneously is infinitesimal when compared to the risk that wind power will be zero (or close to zero).

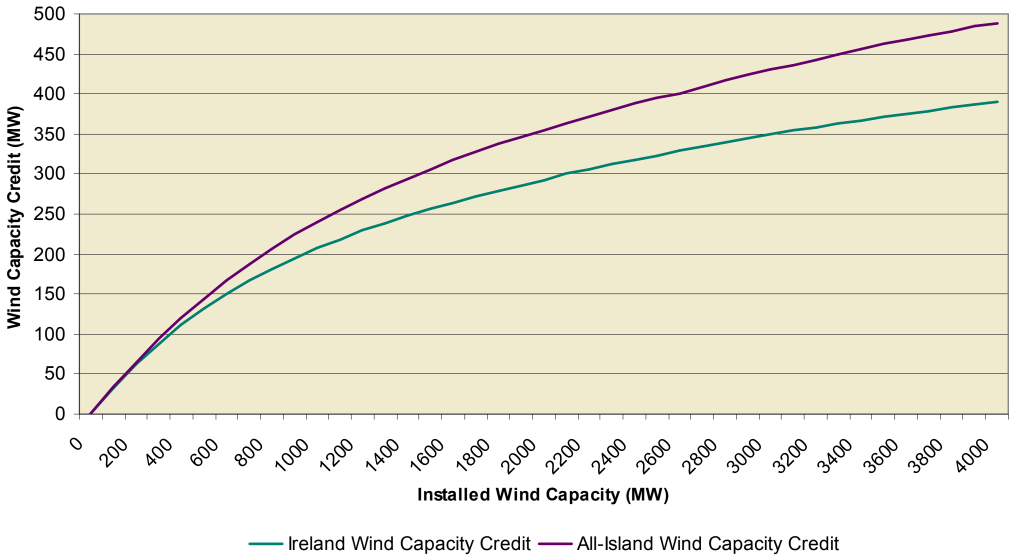

Figure 4.1 Capacity credit of wind generation based on 2006 wind data.

It can also be seen in Figure 4.1 that there is a benefit to the capacity credit of wind when it is determined on an All-Island basis. The reason is that over a greater geographic area, the variations in wind speed are less severe on average. If the wind drops off in the south, it may not drop off in the north or at the very least there will be a time lag. The result is that the variation in wind is reduced and the reliability increases. In comparison to a wind capacity credit based on a wind profile from the Republic of Ireland, an All-Island capacity credit is approximately 100MW higher at 4000MW installed wind capacity.

As a result of the saturating nature of the capacity credit of wind, the installation of large amounts of wind powered generation capacity in line with Government policy targets will not in itself ensure a satisfactory generation adequacy position. Sufficient conventional generation capacity will also be required to ensure that acceptable adequacy positions are maintained.

4.9 All-Island Portfolios

The Republic of Ireland and Northern Ireland are treated collectively as a single system in the development of the All-Island generation portfolio scenarios for 2015, 2020 and 2025.

Generator retirements

A number of generator retirements were assumed based either on announcements by the owners or, in the case of generators in Northern Ireland, based on information from SONI. In addition, based solely on their age, a number of older generators currently in operation are assumed to decommission throughout the timeframe studied. Table 4.3 details the generator retirements assumed in the studies.

Generator	MW	Retirement	Reason
Poolbeg PB1	109.5	Before 2015	ESB Announcement
Poolbeg PB2	109.5	Before 2015	ESB Announcement
Poolbeg PB3	242	Before 2015	ESB Announcement
Tarbert TB1	54	Before 2015	Endesa Announcement
Tarbert TB2	54	Before 2015	Endesa Announcement
Tarbert TB3	241	Before 2015	Endesa Announcement
Tarbert TB4	241	Before 2015	Endesa Announcement
Great Island GI1	54	Before 2015	Endesa Announcement
Great Island GI2	54	Before 2015	Endesa Announcement
Great Island GI3	108	Before 2015	Endesa Announcement
Marina Steam Turbine MR1	27	Before 2015	ESB Announcement
North Wall Steam Turbine NW4	54	Before 2015	Age of Plant
Ballylumford ST5	170	Before 2015	As per SONI
Ballylumford ST6	170	Before 2015	As per SONI
Aghada AT1	90	Before 2020	Age of Plant
Aghada AT2	90	Before 2020	Age of Plant
Aghada AT4	90	Before 2020	Age of Plant
North Wall Gas Turbine NW4	109	Before 2020	Age of Plant
North Wall NW5	109	Before 2020	Age of Plant
Aghada AD1	258	Before 2025	Age of Plant
Marina Gas Turbine MRT	85	Before 2025	Age of Plant

Table 4.3 Generator retirements assumed in the studies.

New generation

A number of new generators including Aghada CCGT, Whitegate CCGT and two new 40MW Gas Turbines at Kilroot are expected to commission in the near future. In addition, Endesa has announced plans to repower the Great Island and Tarbert stations. Table 4.4 summarises these expected new additions to the current generation portfolio. All of the future generation portfolios developed for the All-Island system and used in the studies include these generators.

Generator	MW
Aghada CCGT	420
Whitegate CCGT	445
Kilroot GT3	40
Kilroot GT4	40
Great Island CCGT	403
Tarbert OCGT1	98
Tarbert OCGT2	98
Tarbert OCGT3	98

Table 4.4 Expected new additions to the current All-Island generation portfolio.

All-Island Portfolios

With the solitary exception of the 2015 portfolio, the future All-Island generation portfolios were tuned using CREEP (the adequacy assessment model) to give comparable and acceptable adequacy positions, deemed for this study to be an LOLE of between 5 and 8 hours (a result of exactly 8 hours is difficult to achieve given the discrete sizes in which generation units are commercially available). The base case interconnection scenario of 900MW interconnection to Great Britain is modelled in CREEP by allocating a capacity credit of 250MW for both the Moyle and East-West Interconnectors giving a total contribution to generation adequacy equivalent to 500MW of 'perfect' generating capacity.

2015 Portfolio

The time period to 2015 is a relatively short one when considering the development timeframe required for large-scale generation projects. As a result, rather than considering several possible 2015 portfolios and tuning them to the same adequacy position (between 5 and 8 hours), it was developed as a single 'Best Guess' portfolio resulting in a system with LOLE of less than 1 hour per year. The 2015 'Best Guess' portfolio is detailed in Appendix 3.

2020 Portfolios

Two All-Island portfolios are studied in 2020, both of which build on the 2015 'Best Guess' portfolio. All recent and imminent conventional thermal generator additions to the All-Island system are gas-powered as are the vast bulk of conventional generator applications submitted to EirGrid in recent years by developers seeking connection offers. Therefore, it is conceivable that most, if not all, new conventional thermal plant connecting in the time period to 2020 will also be gas-powered.

- The 2020 'Base Case' portfolio assumes that all new conventional generator additions post-2015 will be CCGTs.
- A 'New Flexible Plant' scenario is also considered which assumes that all new conventional generator additions post-2015 will be OCGTs.

Both 2020 portfolios are detailed in Appendix 5.

2025 Portfolios

A wider range of generation portfolios, five in total, are considered for the 2025 scenario.

- The 2025 'Base Case' portfolio assumes that new conventional generation post-2015 will be a mix of CCGTs and OCGTs.
- A 'New Flexible Plant' scenario is also considered which assumes that all new conventional generation post-2015 will be OCGTs.
- A 'New Coal' scenario considers the possibility of the Moneypoint coal-powered station being decommissioned and replaced with new larger more efficient coal units. In this scenario, additional gas-powered generation in the form of OCGTs are also considered.
- A 'High Renewables' scenario assumes that 8,000MW of wind powered generation capacity is present in the Republic of Ireland in 2025 contributing to an overall renewable energy penetration of 53%. The Republic of Ireland capacity is augmented by 1,528MW of wind powered generation capacity in Northern Ireland giving a total All-Island capacity of 9,528MW. The conventional generation assumptions in this case are the same as for the 'Base Case'.
- A 'High Storage' scenario considers the possibility that 1500MW of new pumped storage capacity is present in 2025. Additional gas-powered generation in the form of OCGTs are also considered but there is less CCGTs and OCGTs than the Base Case.

All the 2025 portfolios are detailed in Appendix 3.

4.10 Great Britain Portfolios

The Great Britain portfolios for 2015, 2020 and 2025 were provided by Ventyx. A single Great Britain portfolio was provided for each of the study years. The generators included in the portfolios consist of existing/installed capacity, defined additions and generic additions. Installed capacity is comprised of the generators that are currently in service. Clearly, this capacity declines over time due to plant retirements. Defined additions are those generators that are under construction and expected to be completed in the near future as well as generators that have obtained consent. Finally, generic additions are additional generators added by Ventyx to replace retired capacity and meet future demand growth. Generic capacity is added based primarily on economics, but also to meet planning reserve margin targets of around 15% to 20%.

The Ventyx Great Britain Energy Market Outlook Autumn 2008 report estimates the total installed capacity in Great Britain to be approximately 78GW. Coal-fired generation and gas-fired generation constitute the largest share with 36% and 32.6% respectively. Nuclear accounts for 14.8% of the total installed capacity and renewables make up 5.6%. The remainder capacity consists of oil-fired generation (5.6%) and pumped storage and hydro (5.2%). Figure 4.2 shows a summary of the installed capacity mix for Great Britain in 2008.

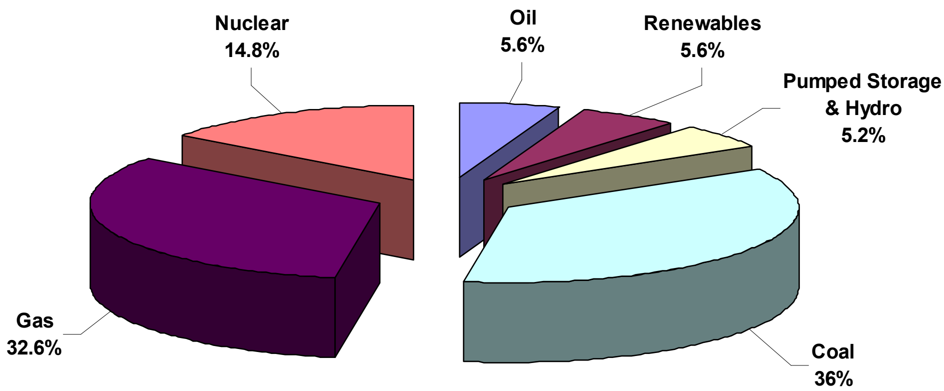

Figure 4.2 Installed capacity mix for Great Britain as at Autumn 2008.

The Great Britain electricity market is expected to undergo significant changes in the period to 2025 with environmental restrictions driving the replacement of 'dirty', high-emissions capacity with 'greener' generation. The Large Combustion Plant Directive 2001/80/EC (LCPD) came into force on 1st January 2008. It controls emissions of sulphur dioxide, nitrogen oxides and particulate matter from large combustion plant (greater than 50MW). The LCPD defines emission limit values which must be met by new combustion plant while existing plant have the option of retiring or alternatively, fitting Flue-Gas Desulphurisation (FGD) technology to enable them to continue operation. Companies who 'opt-out' of fitting FGD must agree to operate for a maximum of 20,000 hours post January 2008 and then close by the end of 2015. In Great Britain, just under one-third of the approximately 28GW of coal generation capacity has opted-out and will be retired.

Until 2020, when low-carbon options such as Carbon Capture and Storage (CCS) technology and nuclear plant are assumed to be commercially viable/available, the replacement plant for the opted-out coal generation is expected to be largely gas-fired CCGT plant. Ventyx analysis shows that a major CCGT new build programme is in place with over 7GW of plant assumed to commission between now and 2011, almost all of it already under construction. The Ventyx Great Britain Energy Market Outlook Autumn 2008 report predicts little or no new build between 2012 and 2014 with the exception of ongoing renewable generation projects and a CCS demonstration project which is expected to commission in 2014. However, by 2020, over 20GW of additional plant is required to come online to sustain reserve margins and replace retiring plant. Ventyx predicts that less than 20% of this will come from renewable generation. As already stated, given the current environmental restrictions and cost of new build 'clean' coal generation, Ventyx assume that all of the new build conventional generation will be gas-fired. Post-2020, further additions are required to meet demand growth and offset retirements. At this point, Ventyx assumes that CCS technology will be commercially viable and that aging British nuclear plant will have been replaced (but not operational before 2020). Hence, generation additions post-2020 are a mix of CCS coal-fired generation, gas-fired generation (CCGT and OCGT) and nuclear generation.

Great Britain Renewables

The UK government has set targets of generating 10% of the UK's electricity from renewable generation by 2010 and 20% by 2020. Ventyx believes that it is unlikely the UK will meet such ambitious targets. In Ventyx's renewable energy forecast, after an initial expansion in biomass co-firing, wind powered generation is expected to be the predominant renewable energy technology installed. Other renewable technologies are expected to make very small contributions. Based on assumed load factors of 27.5% for onshore windfarms and 36% for offshore windfarms, Ventyx predict that 7.2GW of installed wind capacity will need to be added by 2010 and 21GW will need to be added by 2020 in order to reach the targets. This implies that approximately 2GW of wind powered generation capacity would need to be added each year. Under the current Renewable Obligation (RO) Program with its limited funds and technologies, Ventyx believes that it is unrealistic for the UK to install such a large amount of capacity each year. Hence, Ventyx forecasts renewable generation to account for 7.4% of total generation in 2010 and 15.4% by 2020. Table 4.5 details the assumptions on renewable generation employed in the studies.

	2015	2020	2025
Wind – Onshore	6,647MW	7,799MW	8,681MW
Wind – Offshore	3,845MW	6,128MW	8,642MW
Other Renewables*	2,065MW	2,278MW	2,480MW
% of Total Demand	12.6%	15.4%	18%

* Capacity is equivalent effective capacity i.e. assuming capacity factor of 100%.

Table 4.5 Assumptions on renewable generation employed in the studies.

A summary of the installed capacity mix for Great Britain in 2015, 2020 and 2025 is shown in Figures 4.3, 4.4 and 4.5. Note that the Small-Scale Generation capacity detailed in the graphs is equivalent effective capacity i.e. assuming capacity factor of 100%.

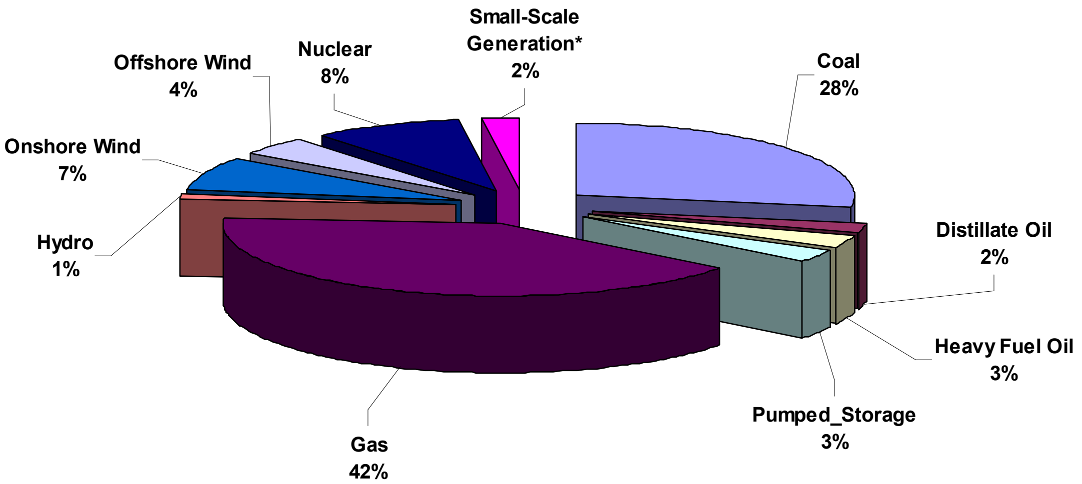

Figure 4.3 Installed capacity mix for Great Britain in 2015.

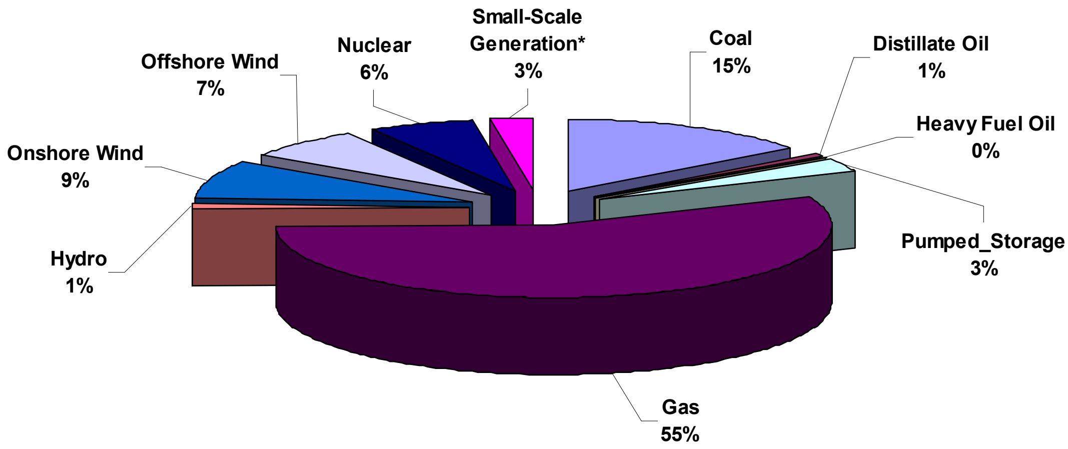

Figure 4.4 Installed capacity mix for Great Britain in 2020.

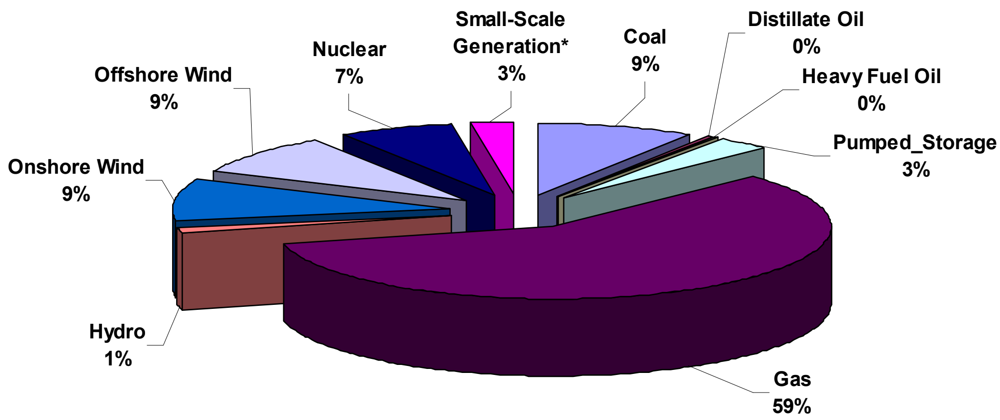

Figure 4.5 Installed capacity mix for Great Britain in 2025.

4.11 Demand Forecast

Every year, EirGrid produces a seven-year forecast of future total annual electricity demand in the Republic of Ireland as well as an estimation of future peak demand. Three demand forecasts (low, median and high) are prepared and published in the annual Generation Adequacy Report. The demand forecast employed in this study is the median forecast from the Generation Adequacy Report 2009-2015. The median forecast predicts an average annual Total Electricity Requirement (TER) growth of 2.6% to 2015 and an average annual TER Peak demand growth of 2.5%. These average growth rates are used to extrapolate demand to 2020 and 2025 producing the forecast for these study years.

The demand forecast employed for Northern Ireland is the median forecast from the Seven Year Generation Capacity Statement 2009-2015. As for the Republic of Ireland, the average growth rates during this seven year period (1.6% growth in both electricity peak demand and energy consumption) are employed to extrapolate the forecast to 2020 and 2025. The demand forecasts for Great Britain, France and the Netherlands were provided by Ventyx. Table 4.6 details the demand forecast of all the systems modelled in the study.

To create demand profiles for 2015, 2020 and 2025, it is necessary to use an appropriate base year hourly profile which provides a representative demand profile of each system. Each system profile is then progressively scaled using forecasts of energy and peak. The base year chosen for the profile creation was 2007. EirGrid has detailed information on the 2007 hourly demand profile in the Republic of Ireland while 2007 demand profiles for Northern Ireland and Great Britain were provided by SONI and Ventyx respectively. The demand assumptions for France and the Netherlands are not used explicitly in the studies due to these systems being modelled using forecasted hourly short run marginal cost price profiles. However, for these two systems, the price profiles were derived using the demand forecasts shown in Table 4.6.

	2015 Energy (GWh)	2015 Peak (MW)	2020 Energy (GWh)	2020 Peak (MW)	2025 Energy (GWh)	2025 Peak (MW)
Republic of Ireland	34,842	6,050	39,766	6,865	45,119	7,779
Northern Ireland	10,430	1,897	11,314	2,057	12,206	2,231
Great Britain	365,983	66,966	377,095	69,342	388,544	71,804
France	531,003	93,681	558,089	98,332	584,519	102,989
Netherlands	135,392	22,485	145,735	24,203	153,823	25,546

Table 4.6 Demand forecasts employed in the studies

Since the publication of EirGrid's Generation Adequacy Report 2009-2015 and SONI's Seven Year Generation Capacity Statement 2009-2015, the economic situation has deteriorated and it is now markedly different from economic forecasts made in 2008. This has also coincided with a reduction in electricity demand in 2009. In the light of this significant change, both EirGrid and SONI recently revised their demand forecasts. The new demand forecasts were not employed for this report as the studies and analysis had already been performed prior to their publication. However, this would not be expected to have a material impact on the results in this report as all of the future All-Island generation portfolios were tuned to give comparable and acceptable generation adequacy positions (deemed for this study to be an LOLE of between 5 and 8 hours). If the revised demand forecast were employed, the portfolios would also have been tuned to provide an equivalent level of risk with respect to supply shortages occurring.

4.12 Fuel Prices

The Republic of Ireland, Northern Ireland and Great Britain are modelled at individual generator level. For the All-Island and Great Britain systems, the fuel and carbon prices employed are critical to the decision as to which units are committed and dispatched with consequent impact on both overall system production costs as well as interconnector flows with neighbouring systems. In this study, the Republic of Ireland and Northern Ireland are modelled using the same fuel price assumptions with the Great Britain prices differing slightly due to different transport costs, tax adders etc. built into the fuel price forecasts. Two distinct fuel price scenarios are studied: (1) Base Case and (2) Alternative Fuel Price Scenario. Tables 4.7, 4.8 and 4.9 detail the fuel price assumptions for both scenarios for the Republic of Ireland and Northern Ireland in 2015, 2020 and 2025 respectively.

Fuel Type	Scenario 1: Base Case €cents/net GJ	Scenario 2: Alternative Fuel Prices €cents/net GJ
Gas	702.5	614.2
Coal	212.0	322.0
Low Sulphur Fuel Oil (LSFO)	640.2	607.9
Distillate Oil	1206.7	1118.8
Peat	318.0	318.0

Table 4.7 Fuel price assumptions for the Island of Ireland (2015)

Fuel Type	Scenario 1: Base Case €cents/net GJ	Scenario 2: Alternative Fuel Prices €cents/net GJ
Gas	702.5	732.4
Coal	212.0	337.9
Low Sulphur Fuel Oil (LSFO)	640.2	643.1
Distillate Oil	1206.7	1183.6
Peat	318.0	318.0

Table 4.8 Fuel price assumptions for the Island of Ireland (2020)

Fuel Type	Scenario 1: Base Case €cents/net GJ	Scenario 2: Alternative Fuel Prices €cents/net GJ
Gas	702.5	822.9
Coal	212.0	352.1
Low Sulphur Fuel Oil (LSFO)	640.2	680.7
Distillate Oil	1206.7	1252.9
Peat	318.0	318.0

Table 4.9 Fuel price assumptions for the Island of Ireland (2025)

The fuel prices in Tables 4.7, 4.8 and 4.9 are annual averages with the seasonal swing captured by using monthly fuel prices for Gas, Low Sulphur Fuel Oil and Distillate Oil. In addition, these fuel prices are exclusive of the cost of Carbon. The assumptions on Carbon price are detailed in Table 4.10. The PROMOD modelling tool factors in the cost of CO_2 emissions when committing and dispatching plant.

Year	€/tonne of CO_2
2015	36.8
2020	41.6
2025	42.7

Table 4.10 Assumptions on Carbon price

Importantly, while the France and Netherlands system models do not require fuel (or Carbon) prices as a direct input, the hourly price profiles for each study year used to model them were calculated using the different fuel price assumptions and therefore their price profiles are different for the two fuel price scenarios.

4.13 Technology and Costs

4.13.1 High Voltage Direct Current Technology

Electricity systems transmit power efficiently over long distances on high voltage lines carrying alternating current (HVAC). Where cable must be used, such as under-sea power transmission, HVAC will only work for short distances. In order to transmit power over longer distances using cable, the use of High Voltage Direct Current (HVDC) is required. This requires a converter station at both ends of the cable to convert electricity from AC to DC and back again. Figure 4.6 shows the main components of a HVDC interconnection scheme.

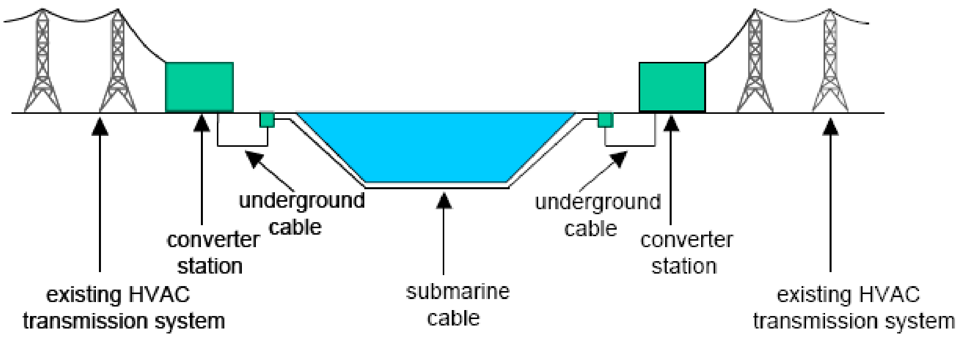

Figure 4.6 Components of a HVDC interconnection scheme.

The two main components of a HVDC interconnection scheme are the DC cables and converter stations.

DC cables can be operated as single pole (or monopole) and bi-pole. The cables tend to be the major cost in a HVDC system. There are different types of cables which are best suited to different applications depending on distance, capacity to be transmitted, voltage level and type of converter station.

With converter stations, there are two types – Line Commutated Conversion (LCC) and Voltage Source Conversion (VSC). LCC is the older technology and it is a well proven technology. This is its main advantage plus the fact that it is capable of transmitting large amounts of power (>500MW). VSC is a new technology that has been commercially implemented in the last 10 years. It is more flexible than LCC, can connect weak AC networks and provide additional services such as reactive support and blackstart capability. The disadvantages of VSC are higher transmission losses and it can't, as yet, transmit greater than 500MW. VSC is still a developing technology and it would be expected that it will improve in time to supplant LCC technology in most applications.

For reference, the Moyle Interconnector consists of LCC converter stations and two single pole cables. The East-West Interconnector will have VSC converter stations and bi-polar cables.

In considering the size of interconnectors, we have used the East-West Interconnector as the model of the best available in the market at the moment and which is most appropriate to Ireland's power system.

Hence, we have opted for an interconnector size of 500MW. There are disadvantages with a larger interconnector size as the power system would have to carry enough reserve to cater for its loss. With Moyle and East-West giving a total interconnection of 900MW to Great Britain, we have modelled an additional 1000MW to Great Britain in two blocks of 500MW each. For France, we have done the same by modelling 1000MW interconnection in blocks of 500MW.

4.13.2 Costs

It should be noted that costs will vary, due to different locations, length of interconnection, technologies selected, market conditions and other factors. The following cost analysis is carried out for a 500MW HVDC interconnector such as East-West Interconnector. Based on the estimated capital investment of €601m, and applying an asset depreciation period of 30 years and WACC (Weighted Average Cost of Capital) of 5.63% (pre-tax real rate), the corresponding annualised cost is €43m. A lower capital investment of €500m would give a corresponding annualised cost of €36m.

For an Ireland-Great Britain 500MW interconnector, the range of costs is €36 - €43m p.a.

An interconnector to France would cover a much longer distance. The straight line distance coast-to-coast is 460km. This is without any on-land component. Realistically an Ireland–France interconnector would be 500-600km. By comparison the East-West Interconnector is 256km which includes significant on-land elements in order to connect to transmission strong points. For a 500MW interconnector to France, the converter station costs would be the same but, as the distance is likely to be greater than 500km, the cable costs would be considerably higher than the East-West Interconnector even taking economies of scale into account.

For an Ireland-France 500MW interconnector, the range of costs is €55 - €66m p.a.

5 RESULTS

5.1 Overview of System Simulation Studies

The following results examine the effect of interconnection on various aspects of system operation. In the Base Case, results are given for twelve production cost studies: Four interconnection options, for each of the three years 2015, 2020, and 2025, under the "cheap coal" fuel price scenario (the 'Base Case' fuel price scenario in Tables 4.7, 4.8 and 4.9). In addition, results are given for various other input assumptions: alternative generation plant portfolios such as high wind and new pumped storage station, as well as the "expensive coal" fuel price scenario (the 'Alternative' fuel price scenario in Tables 4.7, 4.8 and 4.9).

The principal results from the studies are:

- Benefits (Reduction in total system production cost).
- Wind Curtailment in the All-Island (AI) system.
- Flows between AI and Great Britain (GB).
- CO_2 Emissions in AI and GB.

In addition, the production cost studies produce hourly System Marginal Prices (SMPs) based on fuel and CO_2 costs. This data can be used as a proxy market price to indicate how generator revenues might be affected by interconnection. Determining a real market price would require modelling markets, which was not within the scope of the study. This data can also give an approximation of the congestion rents associated with AI-GB interconnection. Depending on market arrangements, this rent might represent revenue to the interconnector owner.

5.2 Base Case

The Base Case was examined for three years (2015, 2020, 2025), and assumed:

- Fuel price projections constant from 2015 (the default Base Case "cheap coal" scenario);
- Varying sizes of interconnection between the AI and GB systems: 400MW, 900MW, 1,400MW or 1,900MW;
- Plant additions, predominantly CCGTs.

Sections 5.2.1 through 5.2.4 focus on the following results for the Base Case:

- Benefits (Reduction in total system production cost).
- Wind Curtailment in AI.
- Flows from AI to GB.
- CO_2 Emissions in AI and GB.

In Sections 5.2.5 and 5.2.6, the production cost marginal prices are used as proxy market prices, and results are given for:

- System Marginal Price (SMP).
- Congestion Rent.

5.2.1 Benefit: Reduction in total system production cost

One of the benefits of interconnection is the reduction in total system production cost (fuel and CO_2 cost). Considering the AI and GB systems together, Table 5.1 details the benefits associated with increasing interconnection between AI and GB.

Benefit (€M p.a.)	2015	2020	2025
AI - GB i/c: from 400 to 900 MW	20	43	50
AI - GB i/c: from 900 to 1,400 MW	6	25	27
AI - GB i/c: from 1,400 to 1,900 MW	1	14	12

Table 5.1 Base Case: Reduction in total system production cost for the AI and GB systems.

5.2.2 Wind Curtailment in AI

Wind curtailment in AI is reduced by interconnection with GB. There is negligible wind curtailment on the GB system. Figure 5.1 shows the effect for the AI system.

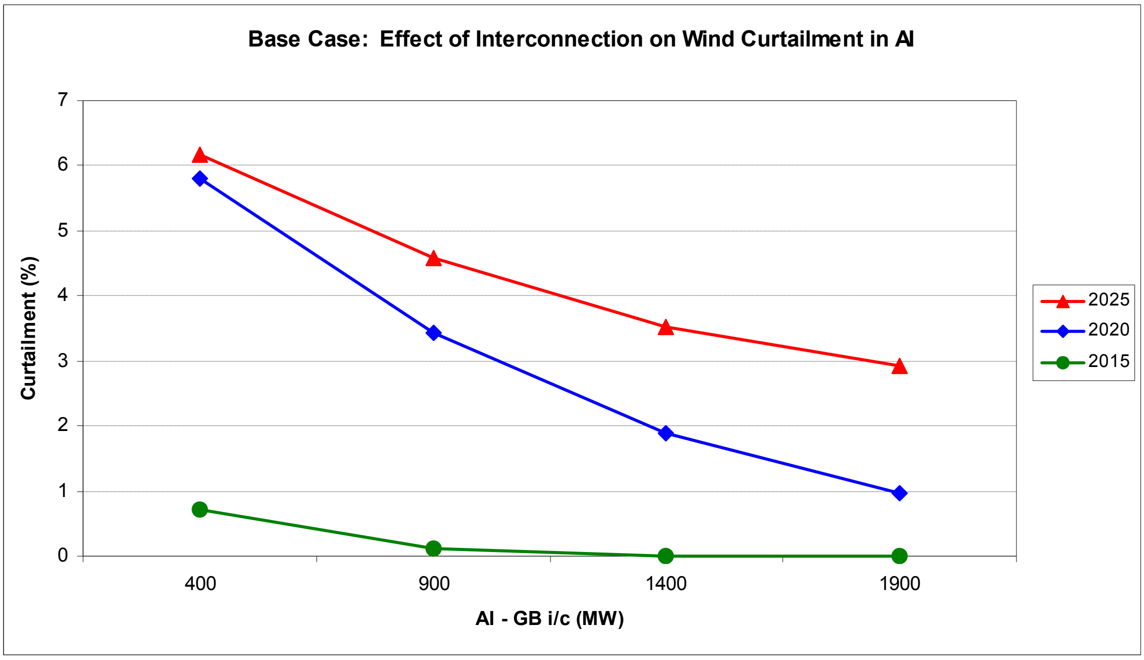

Figure 5.1 Base Case: Effect of Interconnection on Wind Curtailment in 2015, 2020 and 2025.

5.2.3 Flows from AI to GB

The production cost studies produce hourly flows from AI to GB. The following graphs (Figures 5.2, 5.3 and 5.4) show the annual energy values for the different years and interconnection capacity assumptions. The flows in each direction are given, as well as the net flow. The predominant flow is from GB to AI in 2015 and 2025, and the reverse in 2020 (assuming the base case "cheap coal" fuel price projections).

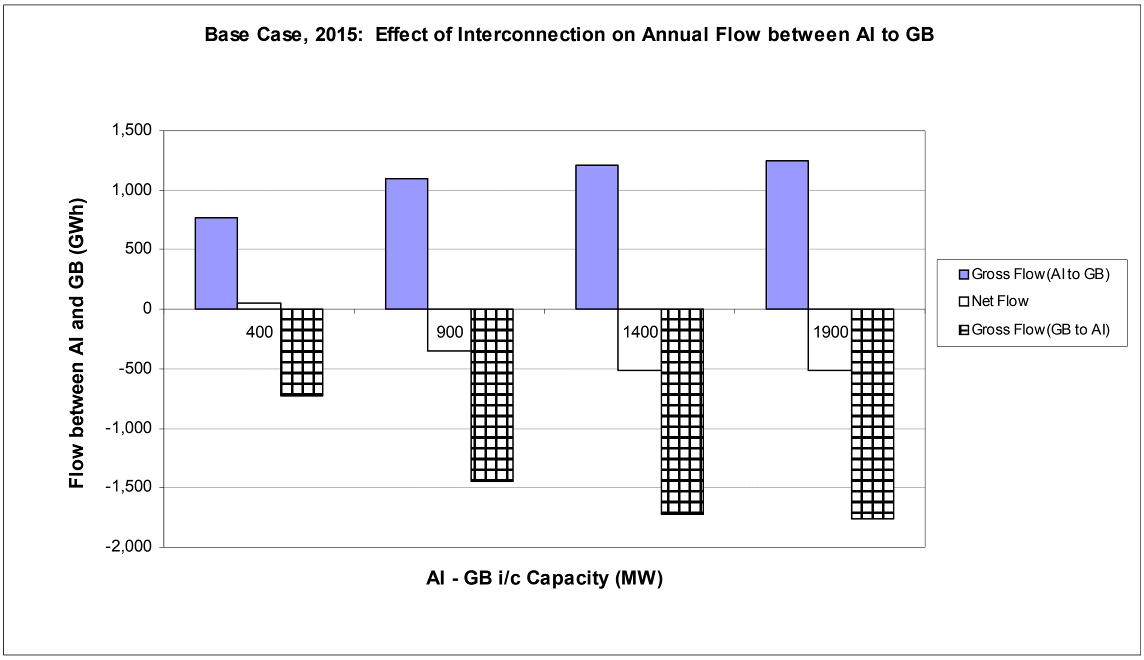

Figure 5.2 Base Case: Effect of Interconnection Capacity on Flow between AI and GB in 2015.

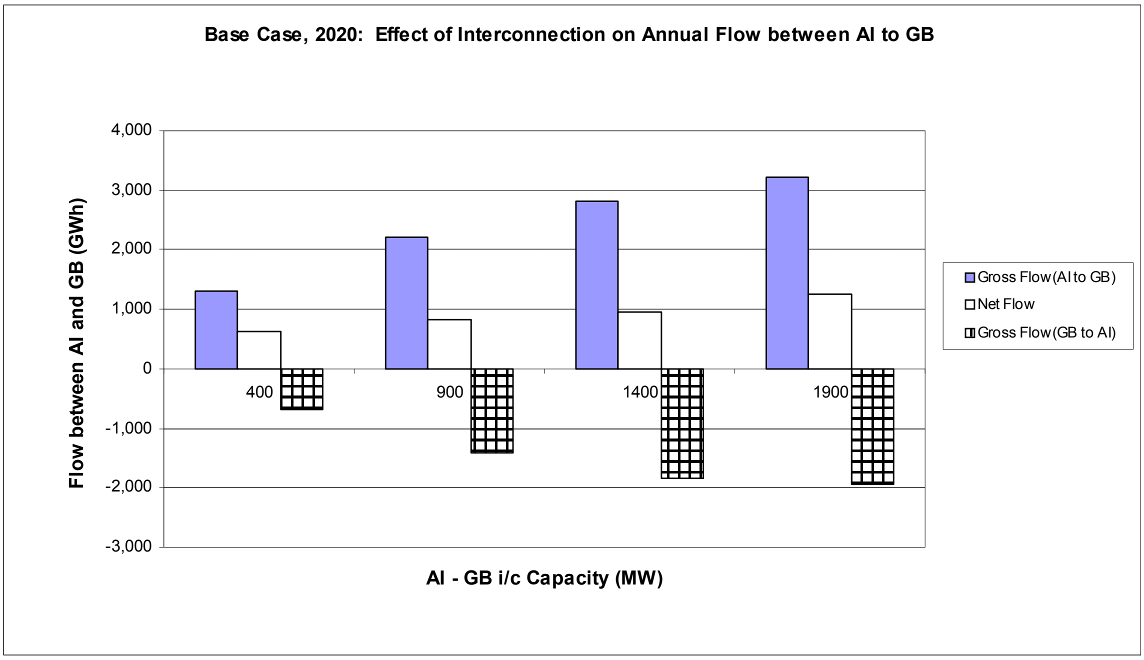

Figure 5.3 Base Case: Effect of Interconnection Capacity on Flow between AI and GB in 2020.

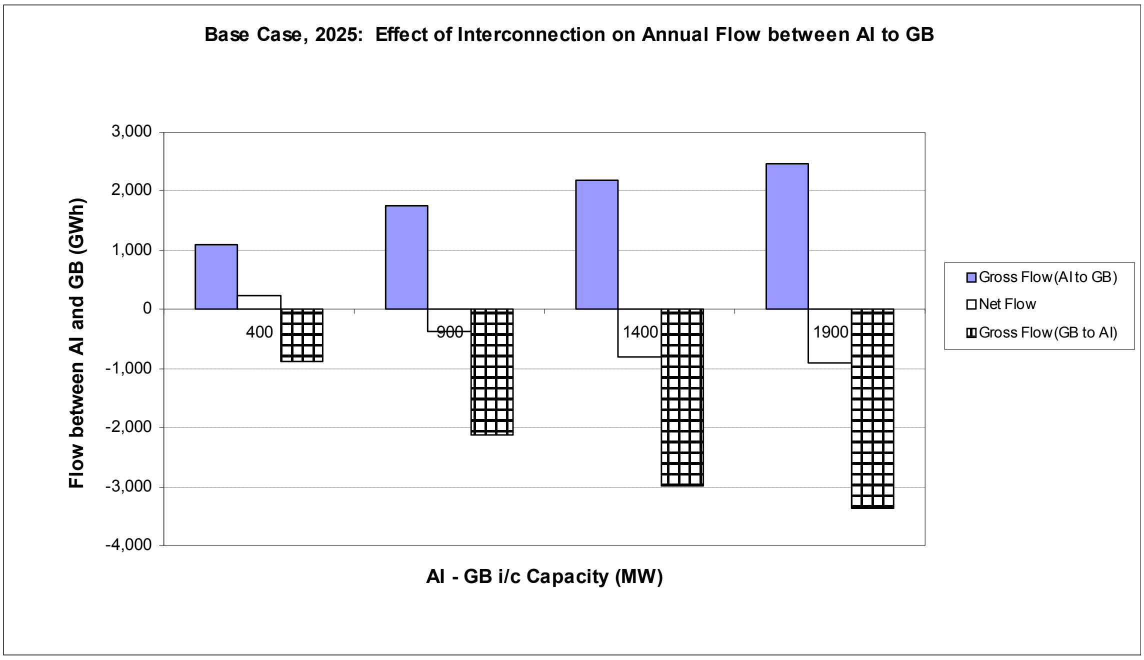

Figure 5.4 Base Case: Effect of Interconnection Capacity on Flow between AI and GB in 2025.

Considering only the net flows, the GWh values were converted to MW giving the average hourly net flow. Figure 5.5 shows the values for the different years and interconnection capacity assumptions. The predominant flow is from GB to AI in 2015 and 2025, and the reverse in 2020.

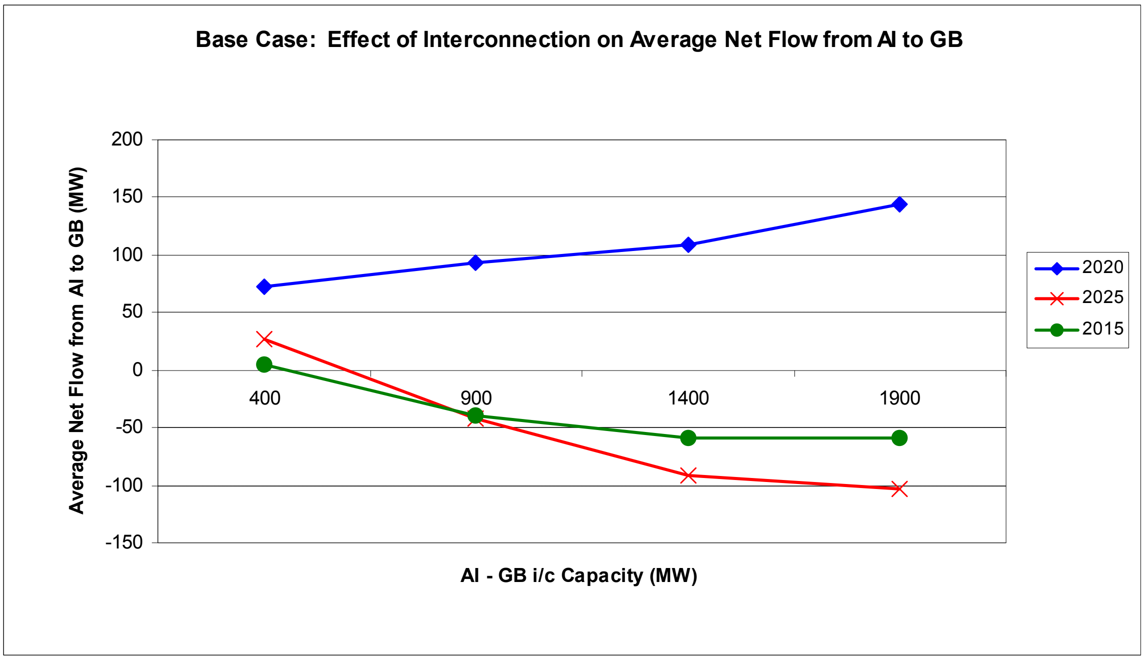

Figure 5.5 Base Case: Effect of Interconnection Capacity on Average Net Flow from AI to GB.

The capacity factor of the interconnector can be determined from the absolute value of the flows, i.e. there is no netting between flows in different directions. Figure 5.6 shows the capacity factors for the different interconnection capacity assumptions. As can be seen, the capacity factor increases over time, and decreases with interconnection capacity.

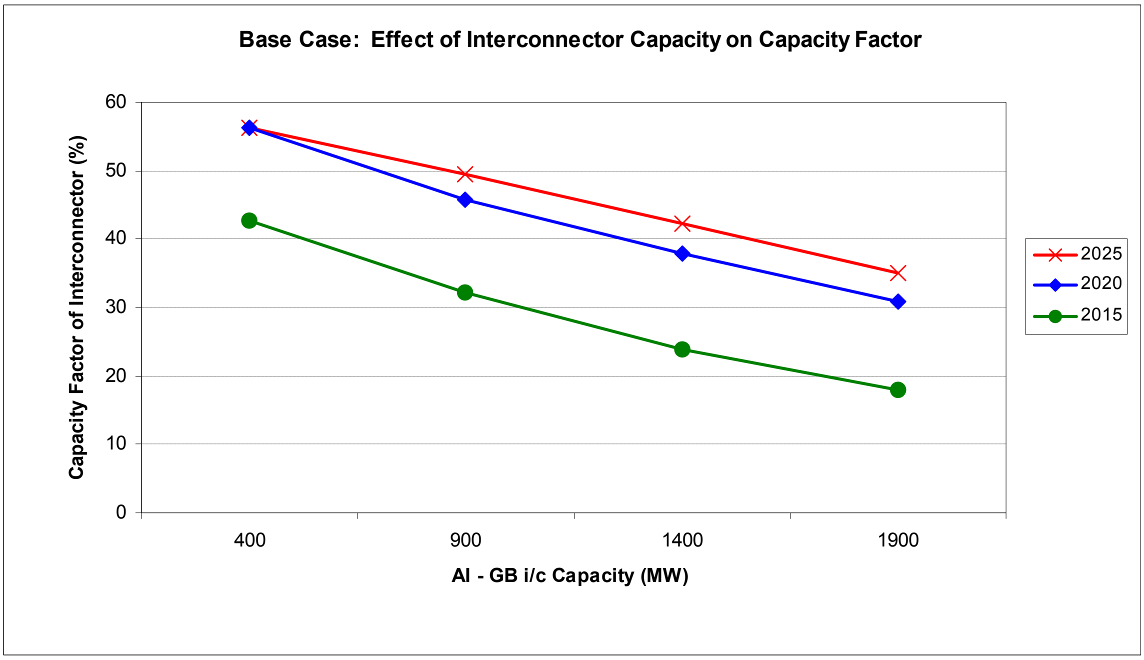

Figure 5.6 Base Case: Effect of Interconnection Capacity on Capacity Factor.

5.2.4 CO2 Emissions

CO_2 Emissions in AI are reduced by interconnection in most cases – see Figure 5.7. The CO_2 decrease from 2015 to 2020 appears to be driven by extra wind generation in that period. The CO_2 increase from 2020 to 2025 is probably related to growth in demand and the relatively small amount of extra wind added in that period.

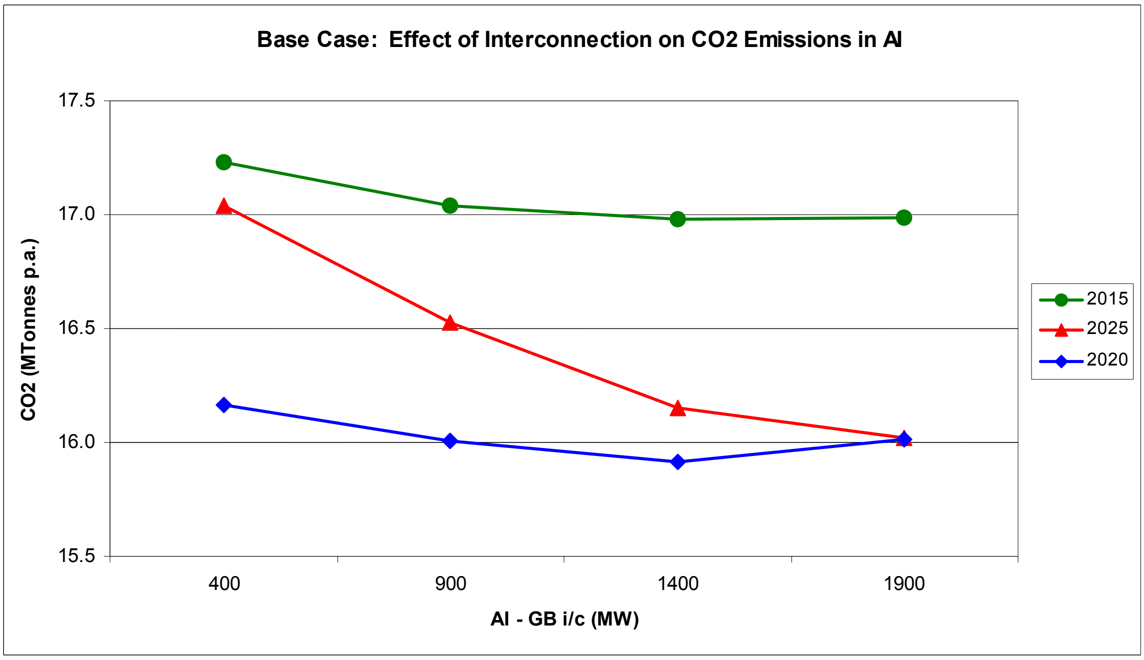

Figure 5.7 Base Case: Effect of Interconnection Capacity on CO_2 Emissions in AI.

The following three graphs (Figures 5.8, 5.9 and 5.10) show the relative effect on CO_2 emissions of increasing interconnection (the 400MW case is the reference point):

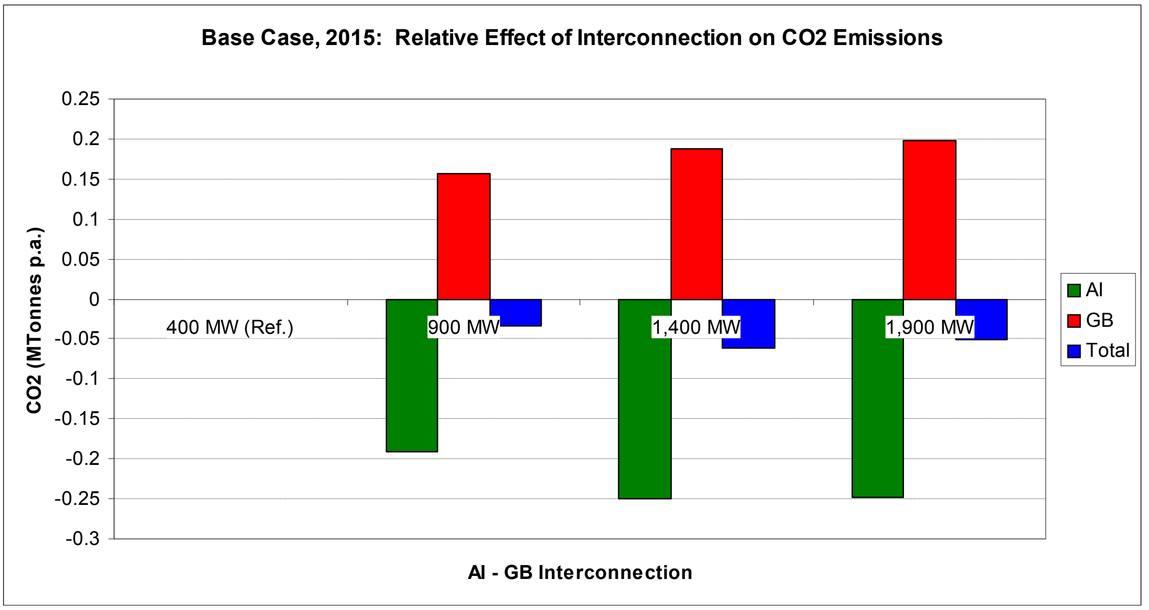

Figure 5.8 Base Case, 2015: Relative Effect of Interconnection on CO_2 in AI and GB.

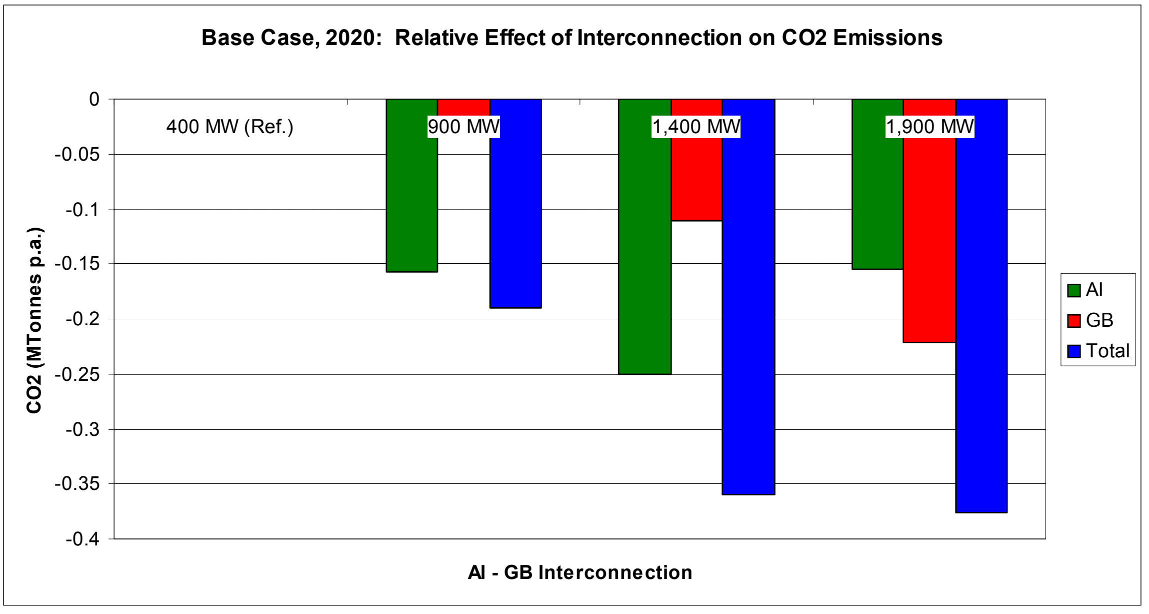

Figure 5.9 Base Case, 2020: Relative Effect of Interconnection on CO_2 in AI and GB.

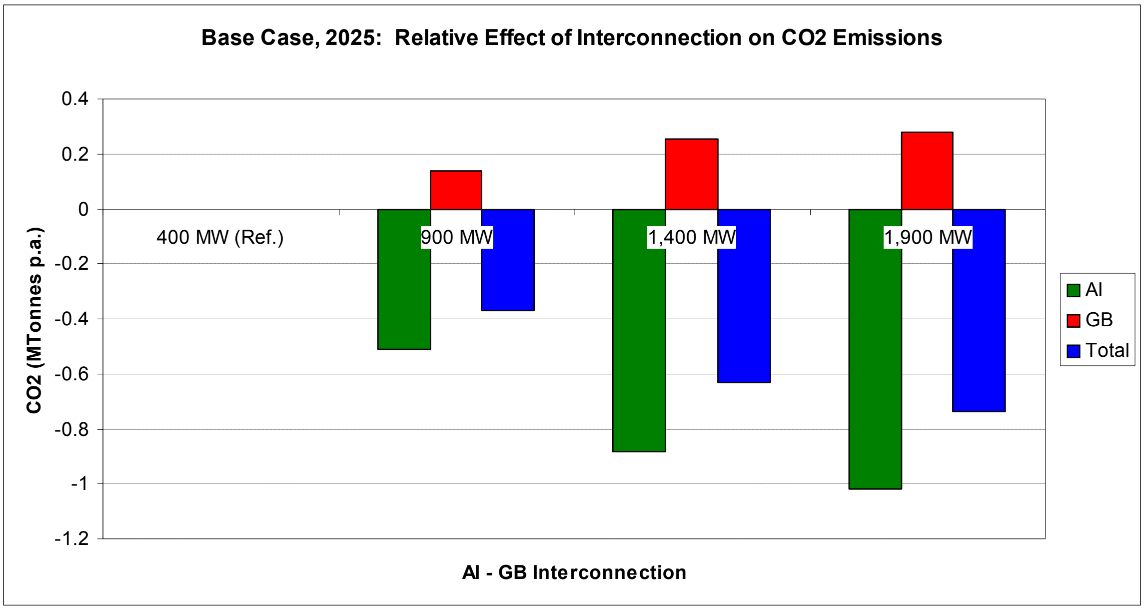

Figure 5.10 Base Case, 2025: Relative Effect of Interconnection on CO_2 in AI and GB.

5.2.5 System Marginal Price (SMP)

The production cost studies produce hourly SMPs based on fuel and CO2 costs. This data can be used as a proxy market price to indicate how generator revenues might be affected by interconnection. Determining a real market price would require market modelling, which was not within the scope of the study.

The following graphs (Figures 5.11, 5.12 and 5.13) show the effect of interconnection on SMP.

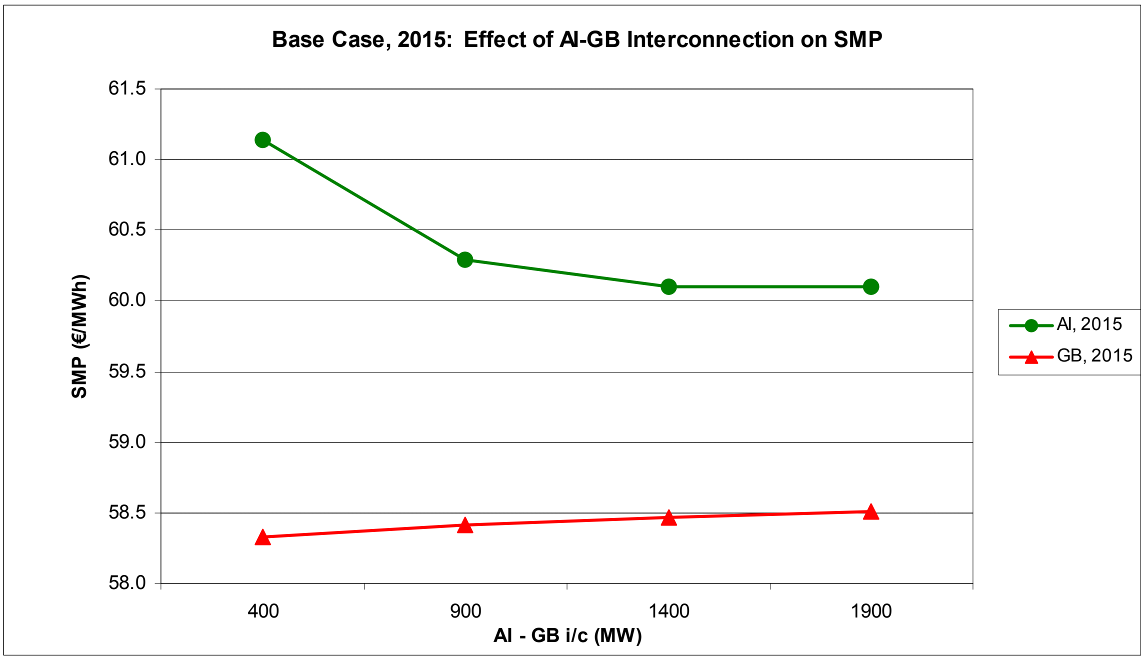

Figure 5.11 Base Case: Effect of Interconnection on SMP in 2015.

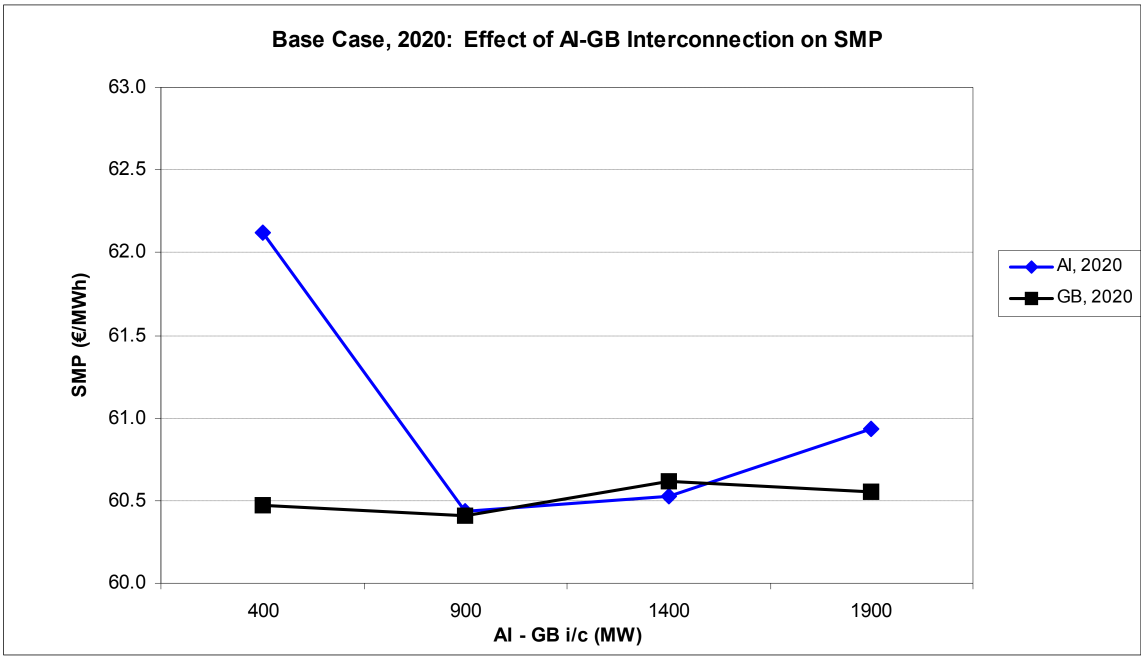

Figure 5.12 Base Case: Effect of Interconnection on SMP in 2020.

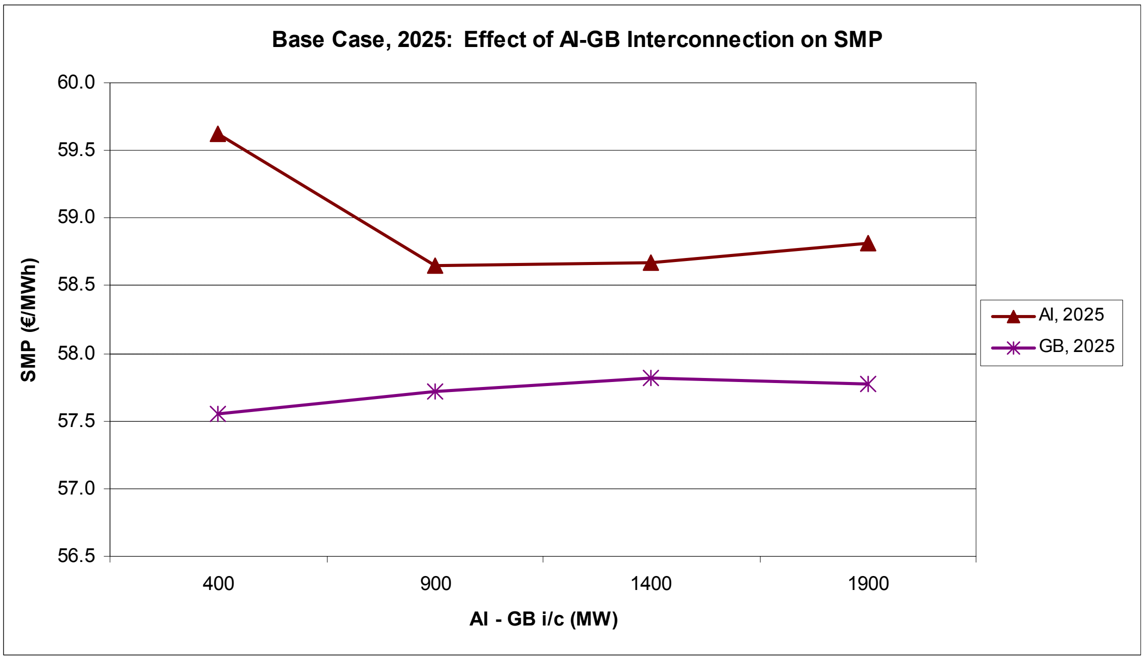

Figure 5.13 Base Case: Effect of Interconnection on SMP in 2025.

5.2.6 Congestion Rent

Another way at looking at the feasibility of interconnectors is to calculate their income. This can come in two forms: capacity payments and congestion rents. We discuss capacity benefit in section 5.5. In this section we examine the likely congestion rents that can be earned by interconnectors. Congestion rents are only earned when the interconnectors are fully utilised. Congestion rent is calculated as the price difference between two nodes in each hour multiplied by the amount of flow in that hour. The production cost studies produce hourly SMPs based on fuel and CO_2 costs. Applying this data as a proxy market price, the congestion rents shown in Table 5.2 apply for the AI-GB interconnector. Depending on market arrangements, this rent might represent a revenue to the interconnector owner.

Capacity of AI - GB i/c	€M / year			€ / (kW x year)		
	2015	2020	2025	2015	2020	2025
400 MW	10	36	32	26	89	79
900 MW	6	39	37	7	44	41
1,400 MW	2	31	28	1	22	20
1,900 MW	0.3	21	18	0.2	11	10

Table 5.2 Congestion Rent in Base Case.

Figures 5.14 and 5.15 illustrate why the congestion rent tends to decrease when the interconnection capacity increases beyond a certain level. Figure 5.14 shows the results in 2015 for a 400 MW link, and Figure 5.15 shows the corresponding results for a 1,400 MW link. The number of hours when the 400 MW interconnector is fully utilised is 1,900 (22% of the year). During these hours, there is a price differential between the two systems. In contrast, the 1,400 MW of interconnection is fully utilised for only 123 hours (1% of the year). The extra volume is not enough to compensate for the reduced usage of the interconnector's full capacity.

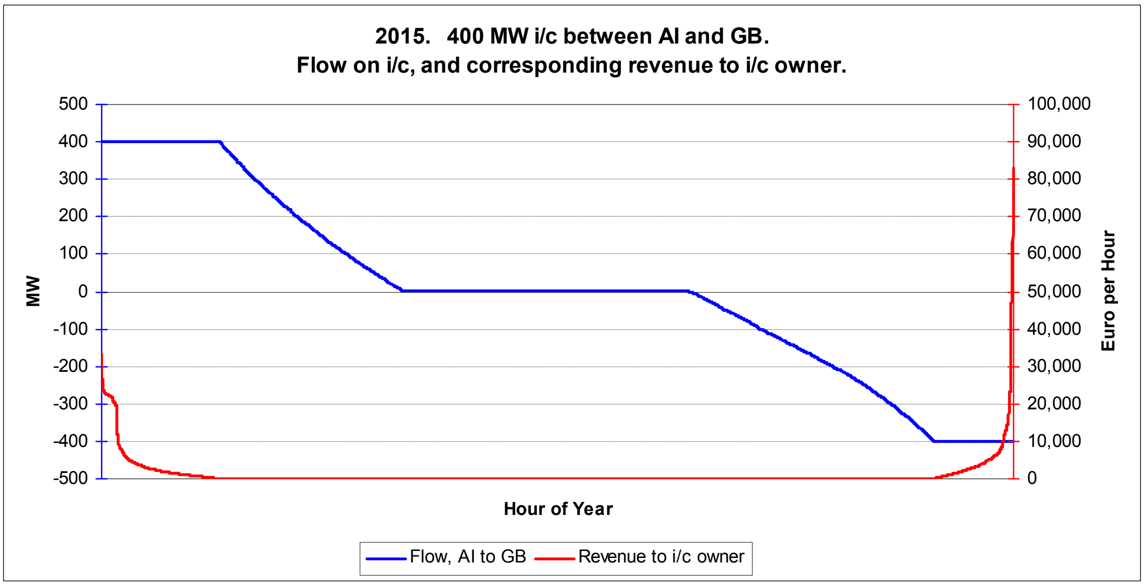

Figure 5.14 Base Case: Flow on 400MW Interconnector and corresponding Congestion Rent.

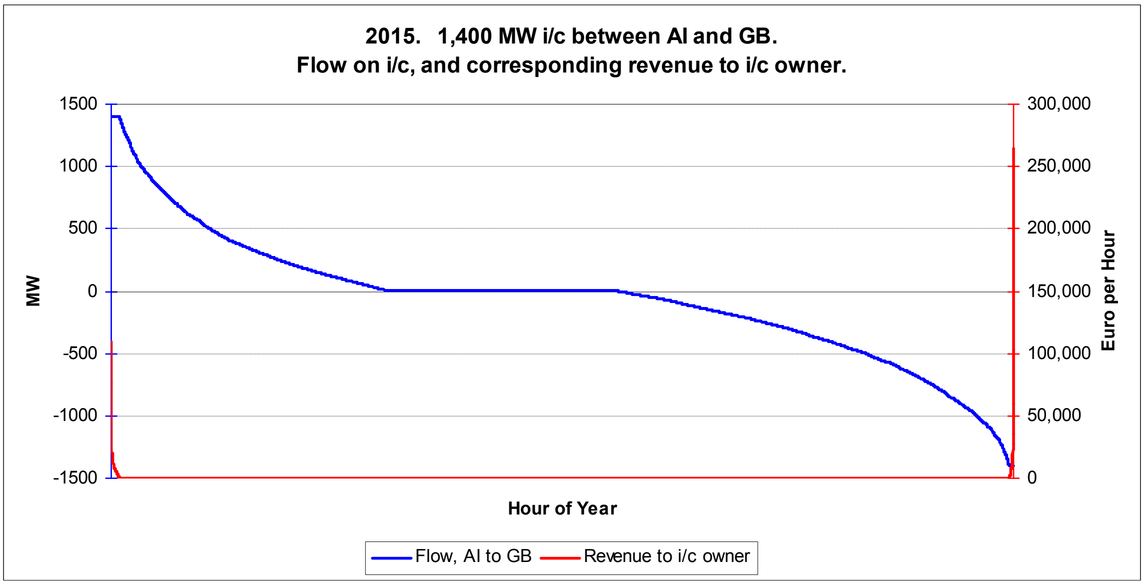

Figure 5.15 Base Case: Flow on 1,400MW Interconnector and corresponding Congestion Rent.

5.3 Sensitivity Studies

The following sensitivity studies were examined for one or more of the years 2015, 2020, 2025:

- Alternative fuel price projections (the 'Alternative' fuel price scenario in Tables 4.7, 4.8 and 4.9, the main feature being the higher coal price) in 2015, 2020, and 2025.
- Large pumped storage station added to AI system in 2025.
- New OCGTs added to AI system in 2020 and 2025, instead of new CCGTs.
- High wind scenario in 2025.
- New coal generators added to AI system in 2025, instead of new CCGTs.

A further sensitivity study was examined: An interconnector between AI and France, in 2015, 2020, and 2025. Interconnector capacities of 500MW and 1000MW were assumed in turn. The results are given in Section 5.3.6.

5.3.1 Sensitivity Study 1: Alternative fuel price projections

Alternative fuel price projections were examined in 2015, 2020, and 2025. The main feature was higher coal prices relative to the Base Case assumptions. The gas price differential changed over time: lower than the Base Case in 2015 and 2020, but higher than the Base Case in 2025.

5.3.1.1 Benefit: Reduction in Total System Production Cost

Considering the AI and GB systems together, the following benefits are associated with increasing interconnection between AI and GB. Results are repeated from the Base Case for comparison purposes.

Benefit (€M p.a.)	Base Case			Sensitivity Study 1		
	2015	2020	2025	2015	2020	2025
AI - GB i/c: from 400 to 900 MW	20	43	50	18	51	60
AI - GB i/c: from 900 to 1,400 MW	6	25	27	6	31	34
AI - GB i/c: from 1,400 to 1,900 MW	1	14	12	1	16	17

Table 5.3 Reduction in total system production cost, Base Case and High Coal price.

The results are similar for both scenarios. Both show a decreasing benefit from extra interconnection, and also an increasing benefit over time in most cases.

5.3.1.2 Wind Curtailment in AI

The High Coal price scenario shows similar wind curtailment compared to the Base Case in 2015, 2020 and 2025. The results are given in Figure 5.16 below, along with results from the Base Case (repeated for comparison purposes).

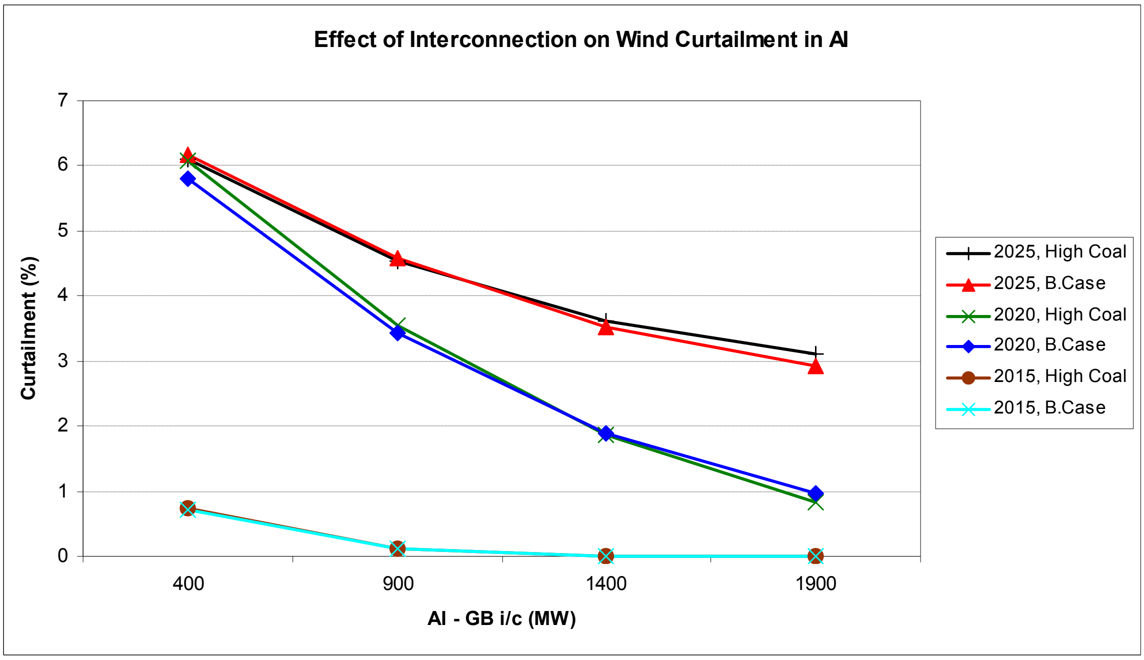

Figure 5.16 High Coal Price: Effect of Interconnection on Wind Curtailment in AI.

5.3.1.3 Flows from AI to GB

The following graphs (Figures 5.17, 5.18 and 5.19) show the net interconnector flows for the different interconnection capacity assumptions. Negative values indicate flow from GB to AI. The Base Case values are shown for comparison purposes. The predominant flow can be in either direction, depending on the year/scenario combination.

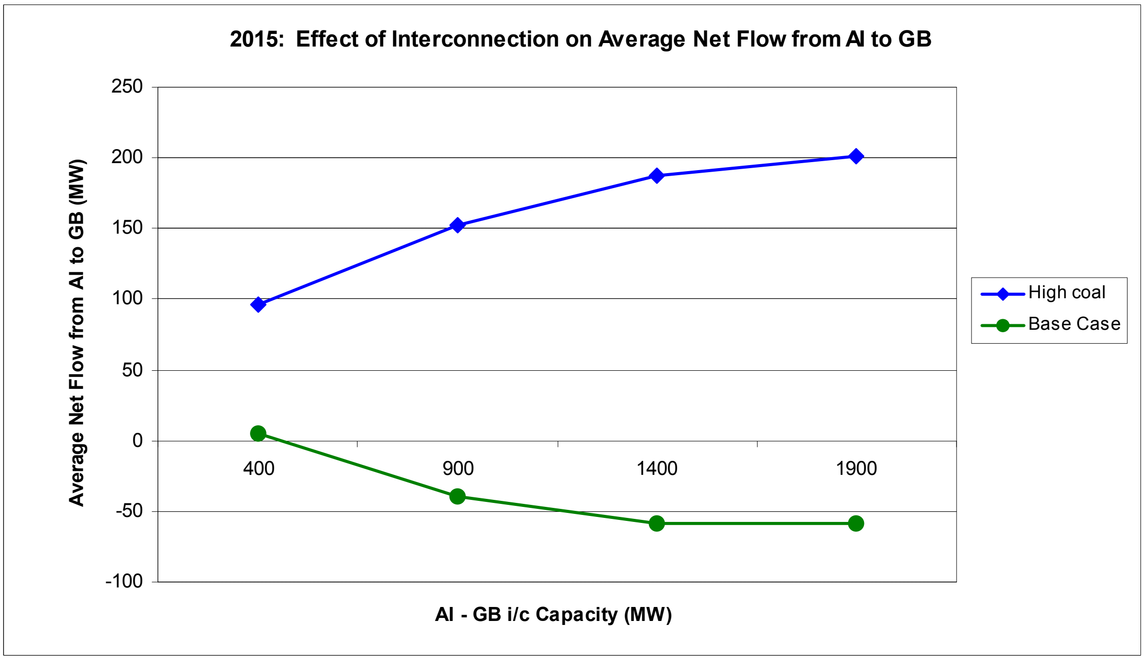

Figure 5.17 High Coal Price: Effect of Interconnection Capacity on Flow in 2015.

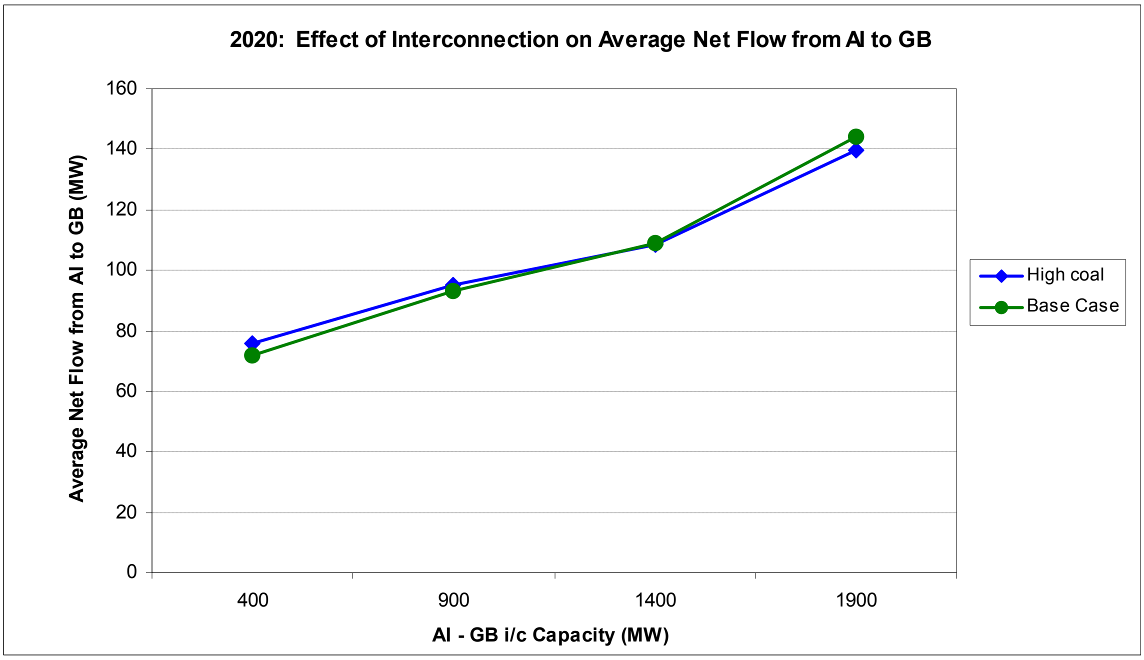

Figure 5.18 High Coal Price: Effect of Interconnection Capacity on Flow in 2020.

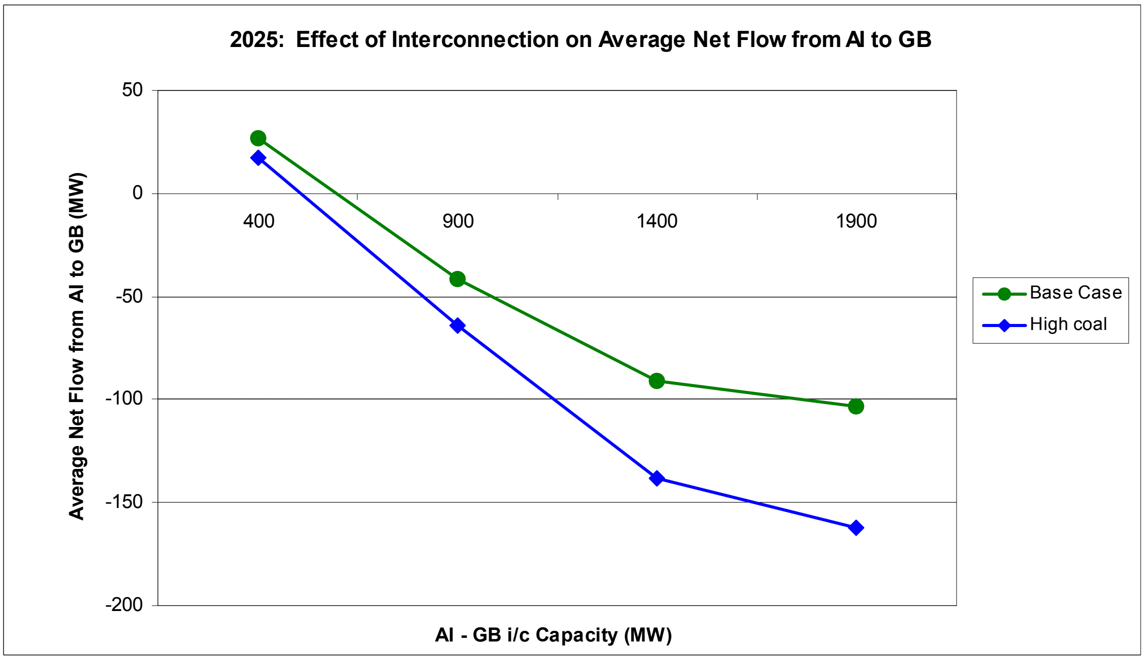

Figure 5.19 High Coal Price: Effect of Interconnection Capacity on Flow in 2025.

The following graphs (Figures 5.20, 5.21, and 5.22) show the capacity factor of the interconnector in 2015, 2020, and 2025 for the different interconnection capacity assumptions. Results are repeated from the Base Case for comparison purposes. The High Coal Price scenario shows more utilisation.

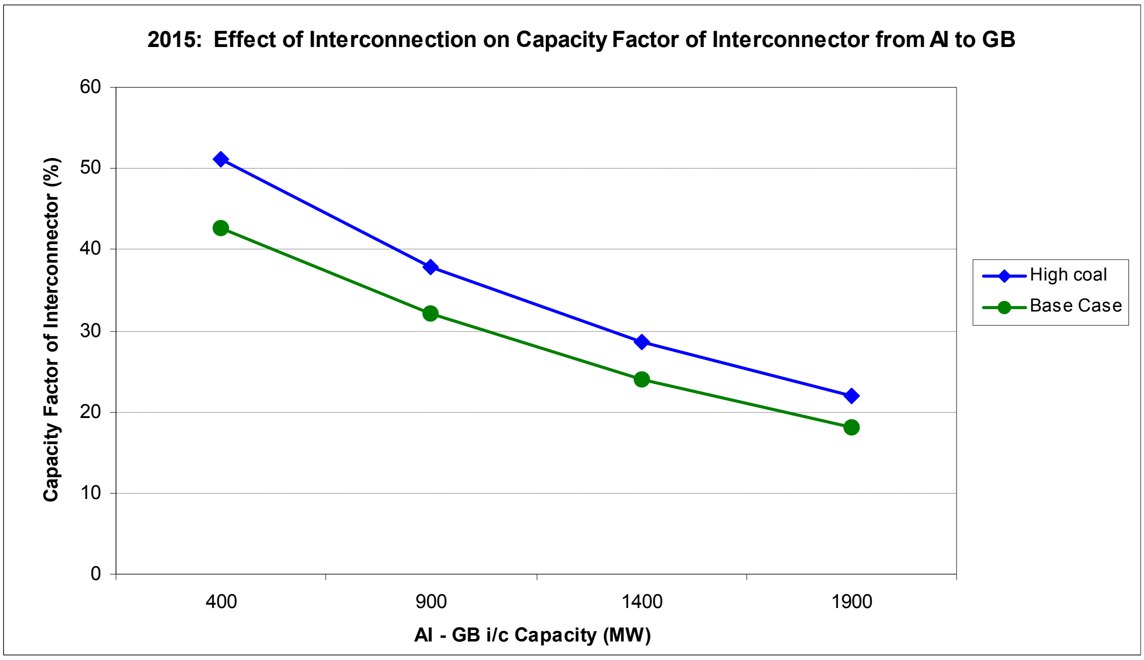

Figure 5.20 High Coal Price: Effect of Capacity on Capacity Factor in 2015.

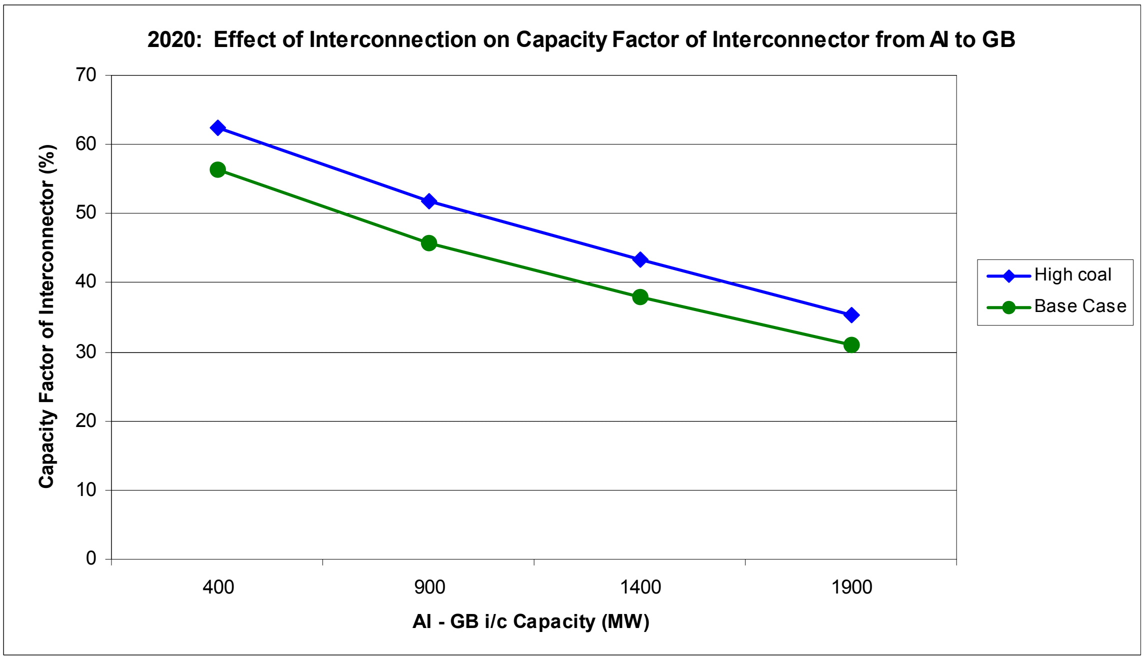

Figure 5.21 High Coal Price: Effect of Capacity on Capacity Factor in 2020.

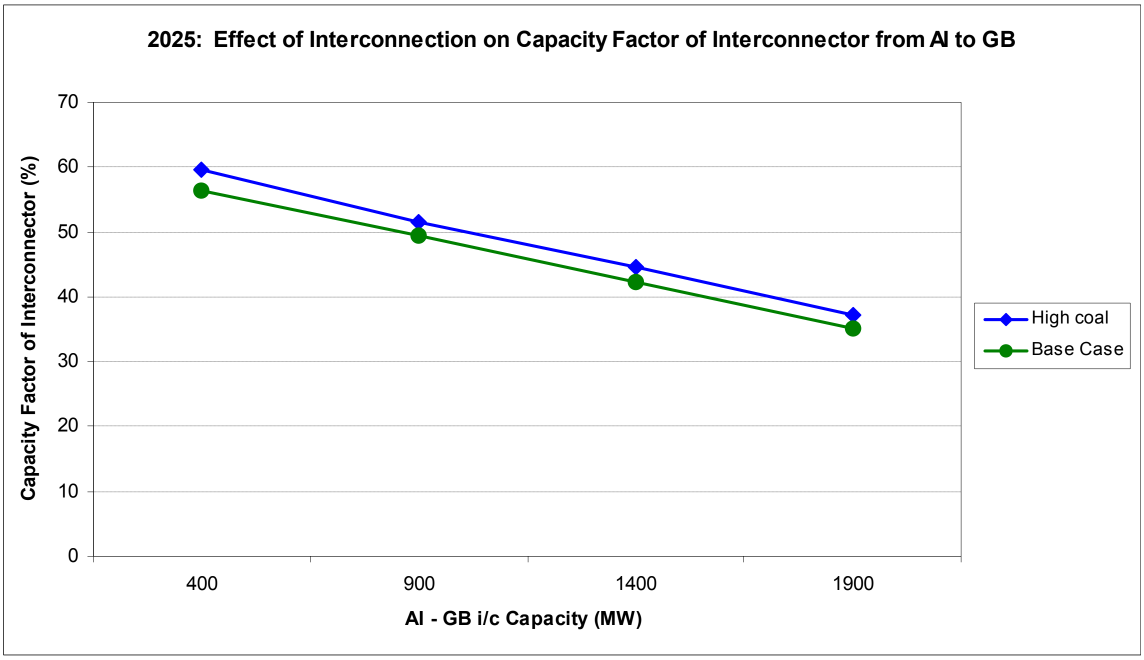

Figure 5.22 High Coal Price: Effect of Capacity on Capacity Factor in 2025.

5.3.1.4 CO2 Emissions

CO_2 Emissions in AI are reduced by the fuel price assumptions in Sensitivity Study 1, relative to the Base Case - see Figures 5.23, 5.24 and 5.25. This is consistent with high coal prices causing CO_2-intensive coal plant to be dispatched less often.

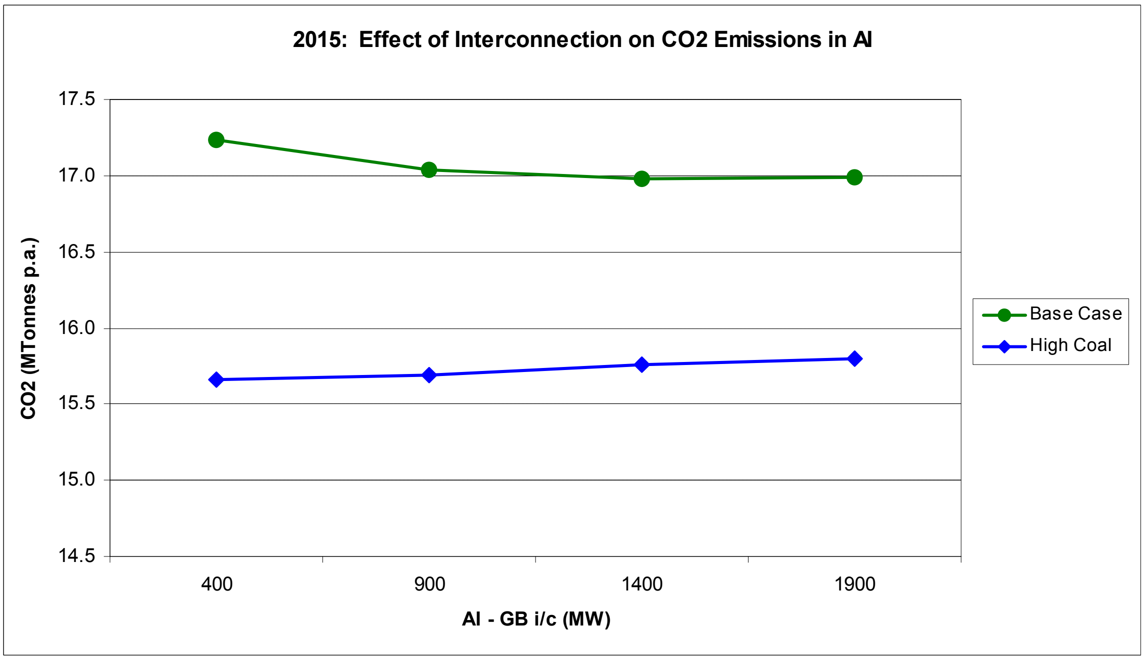

Figure 5.23 Effect of High Coal Price on CO_2 Emissions in AI in 2015.

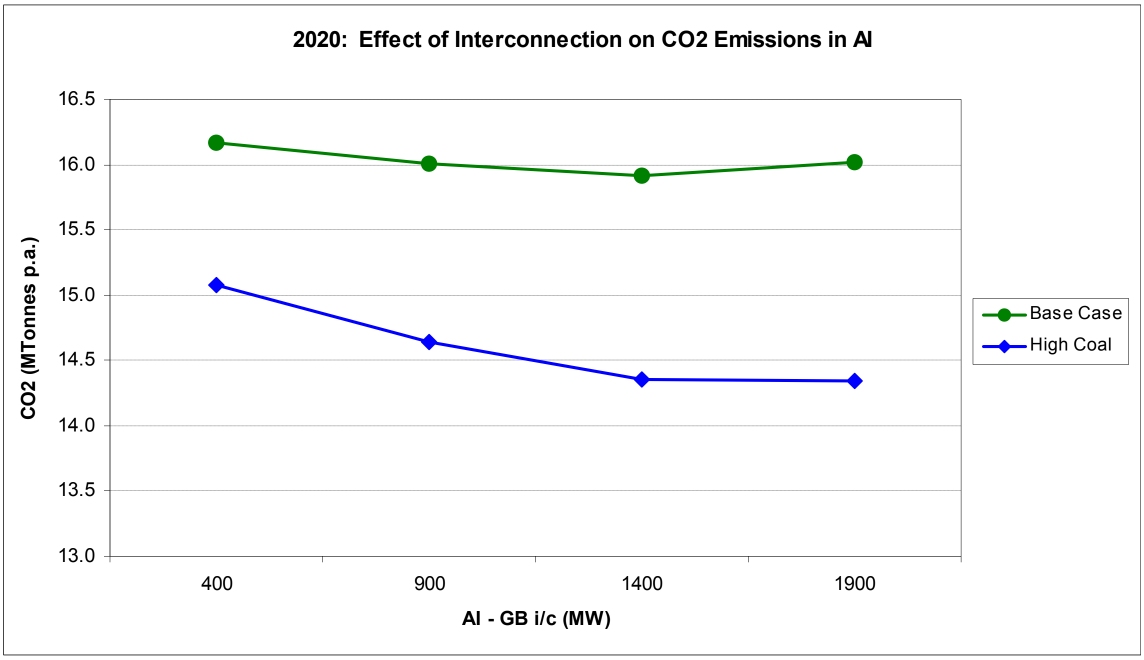

Figure 5.24 Effect of High Coal Price on CO_2 Emissions in AI in 2020.

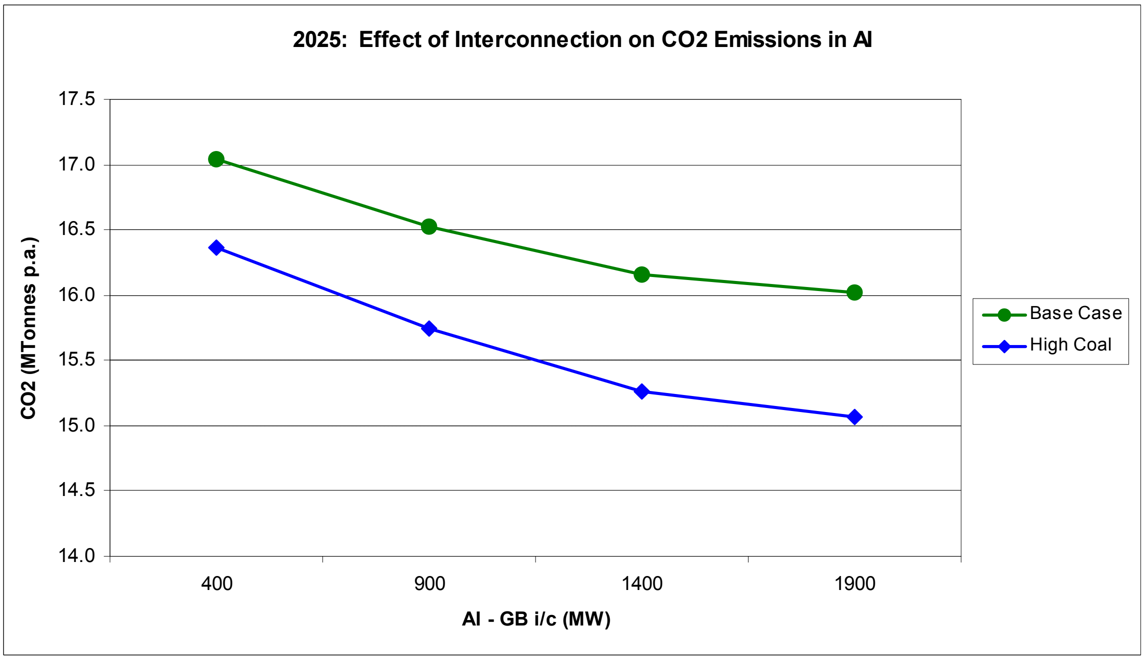

Figure 5.25 Effect of High Coal Price on CO_2 Emissions in AI in 2025.

The following three graphs (Figures 5.26, 5.27 and 5.28) show the relative effect on CO_2 emissions of increasing interconnection (the 400MW case is the reference point).

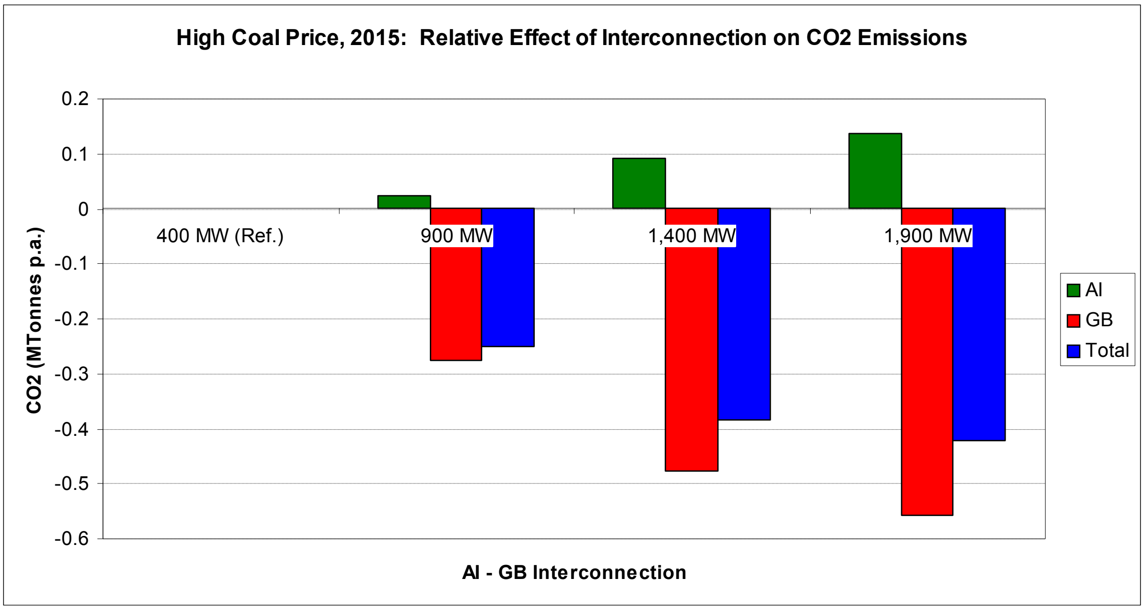

Figure 5.26 High Coal Price, 2015: Relative Effect of Interconnection on CO_2 in AI and GB.

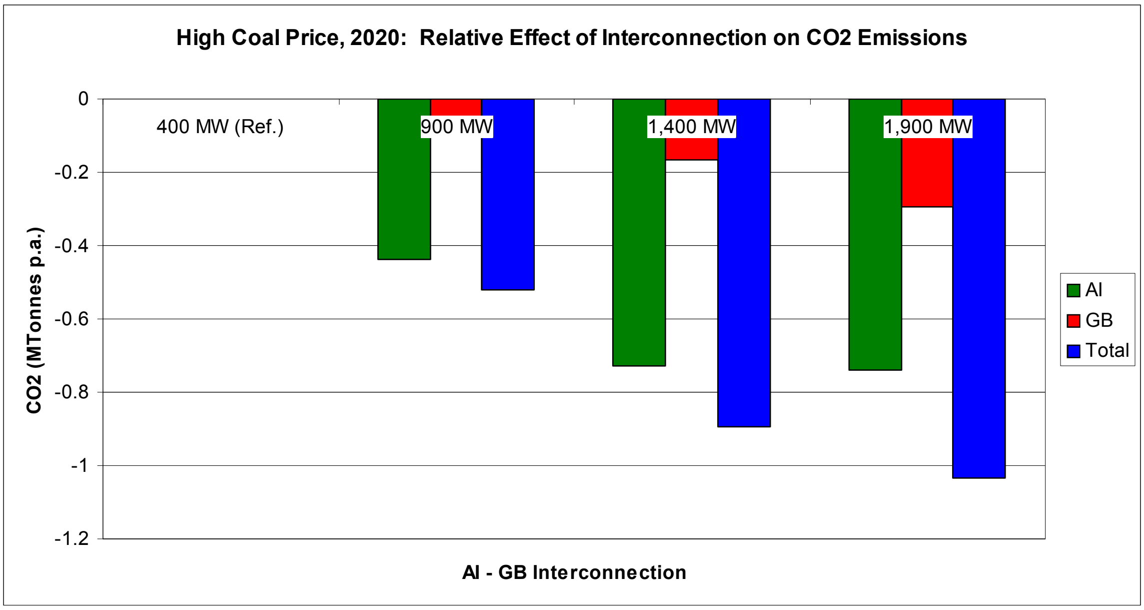

Figure 5.27 High Coal Price, 2020: Relative Effect of Interconnection on CO_2 in AI and GB.

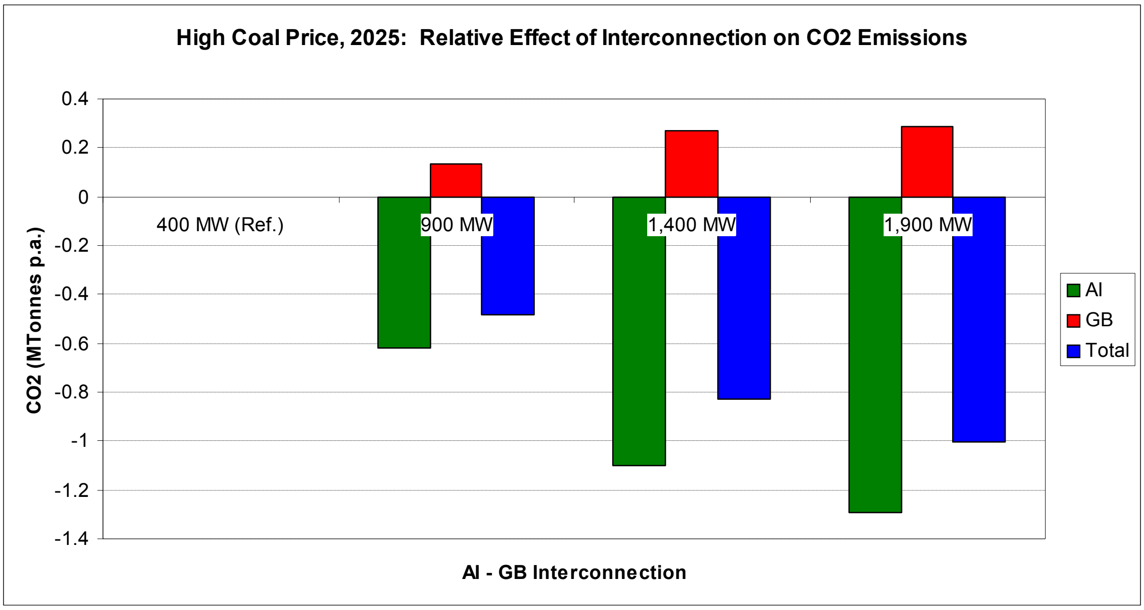

Figure 5.28 High Coal Price, 2025: Relative Effect of Interconnection on CO_2 in AI and GB.

5.3.1.5 System Marginal Price (SMP)

The following graphs (Figures 5.29, 5.30 and 5.31) show the effect of interconnection on SMP in the years 2015, 2020 and 2025. The Base Case values are shown for comparison purposes.

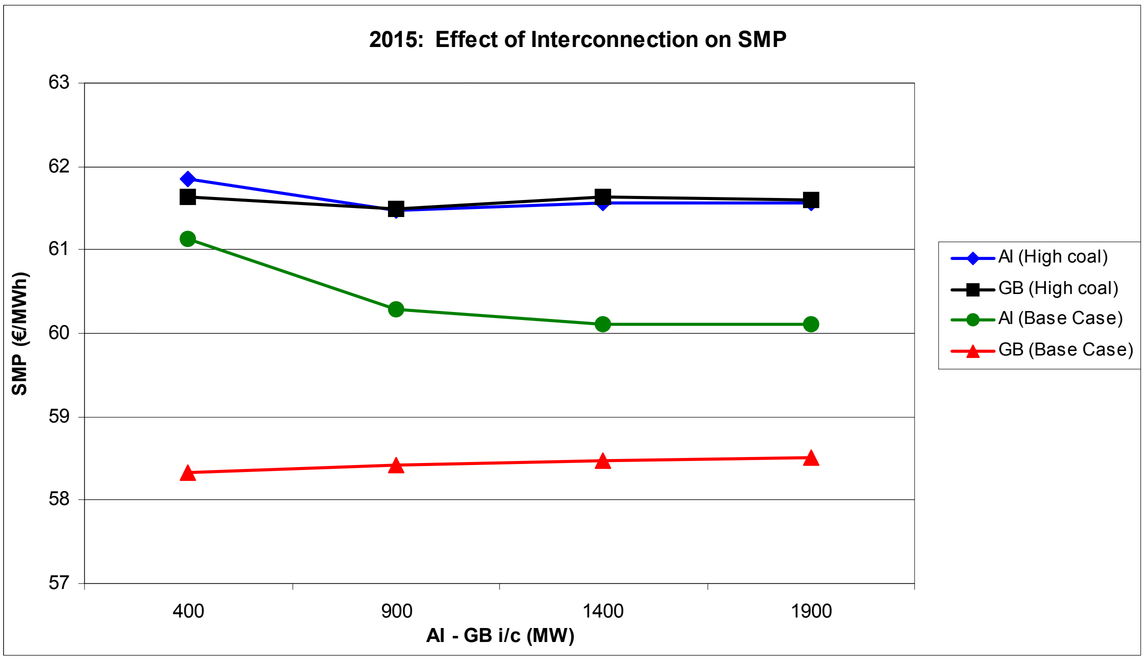

Figure 5.29 Effect of Interconnection on SMP in 2015 (Base Case and High Coal Price).

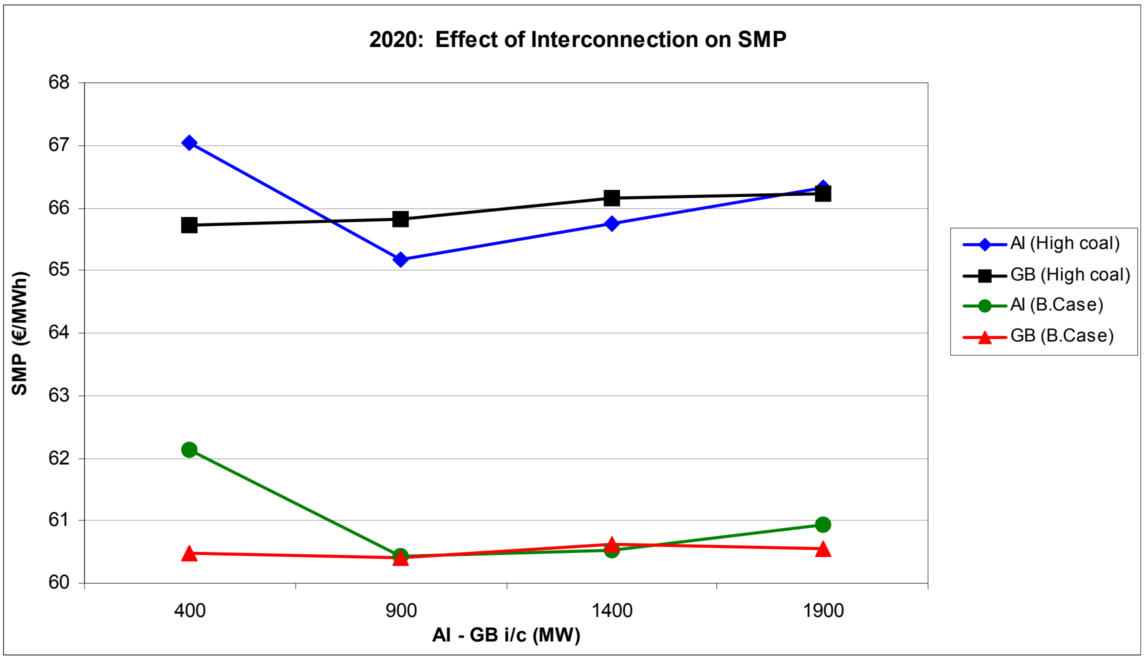

Figure 5.30 Effect of Interconnection on SMP in 2020 (Base Case and High Coal Price).

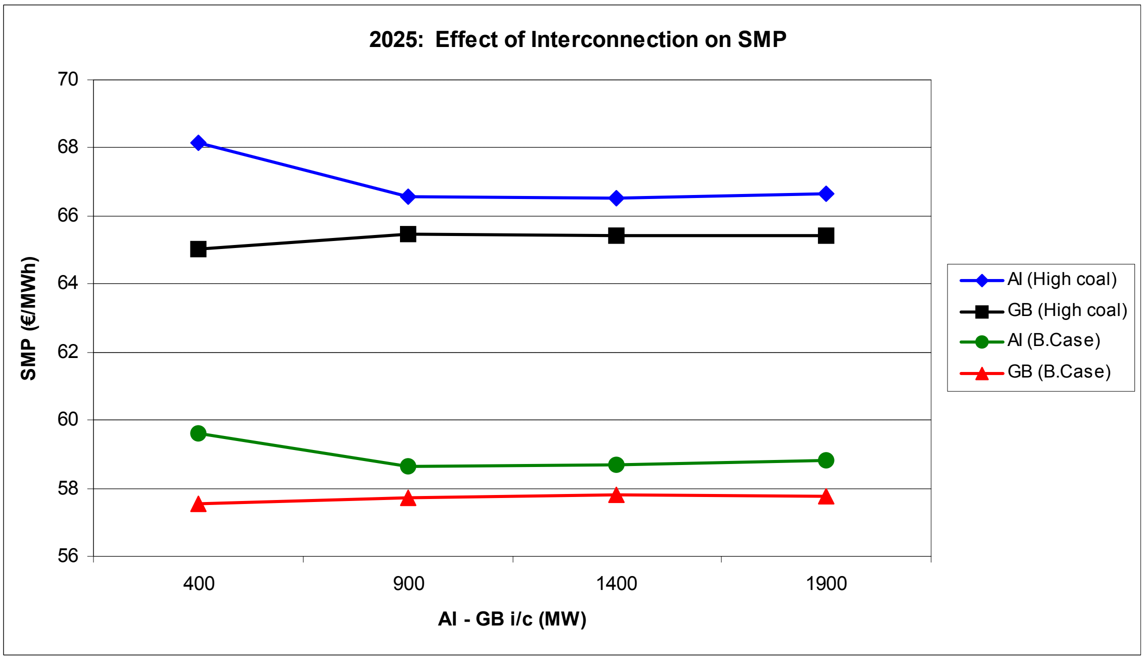

Figure 5.31 Effect of Interconnection on SMP in 2025 (Base Case and High Coal Price).

5.3.1.6 Congestion Rent

Applying the SMPs as a proxy market price, the following congestion rents apply for the AI-GB interconnector – see Tables 5.4 and 5.5. Results are repeated from the Base Case for comparison purposes.

Capacity of AI - GB i/c	Base Case (€M / year)			High Coal Price (€M / year)		
	2015	2020	2025	2015	2020	2025
400 MW	10	36	32	13	40	37
900 MW	6	39	37	9	43	41
1,400 MW	2	31	28	4	36	33
1,900 MW	0.3	21	18	2	24	19

Table 5.4 Congestion Rent in €M/year (Base Case and High Coal Price scenarios).

Capacity of AI - GB i/c	Base Case (€ / (kW x year))			High Coal Price (€ / (kW x year))		
	2015	2020	2025	2015	2020	2025
400 MW	26	89	79	33	100	93
900 MW	7	44	41	9	48	46
1,400 MW	1	22	20	3	26	23
1,900 MW	0.2	11	10	1	13	10

Table 5.5 Congestion Rent in €/(kW x year) for Base Case and High Coal Price scenarios.

5.3.2 Sensitivity Study 2: Large pumped storage station added to AI system in 2025

A large pumped storage station was added to the AI system in 2025. It was rated for 1,500MW capacity and 135GWh of energy (allowing full output for 90 hours). Some CCGT plant was decommissioned (and OCGT plant commissioned) to accommodate the pumped storage plant.

5.3.2.1 Benefit: Reduction in Total System Production Cost

Considering the AI and GB systems together, the benefits associated with increasing interconnection between AI and GB are detailed in Table 5.6. Results from the Base Case are also shown for comparison purposes.

Benefit (€M p.a.)	Base Case	Sensitivity Study 2
AI - GB i/c: from 400 to 900 MW	50	68
AI - GB i/c: from 900 to 1400 MW	27	36
AI - GB i/c: from 1400 to 1900 MW	12	26

Table 5.6 New pumped storage: Reduction in total system production cost.

The large pumped storage station scenario gave larger benefits than the Base Case scenario. Both studies show a decreasing benefit from extra interconnection.

5.3.2.2 Wind Curtailment in AI

The large pumped storage station decreases wind curtailment relative to the Base Case. The results are given in Figure 5.32 along with results from the Base Case (repeated for comparison purposes).

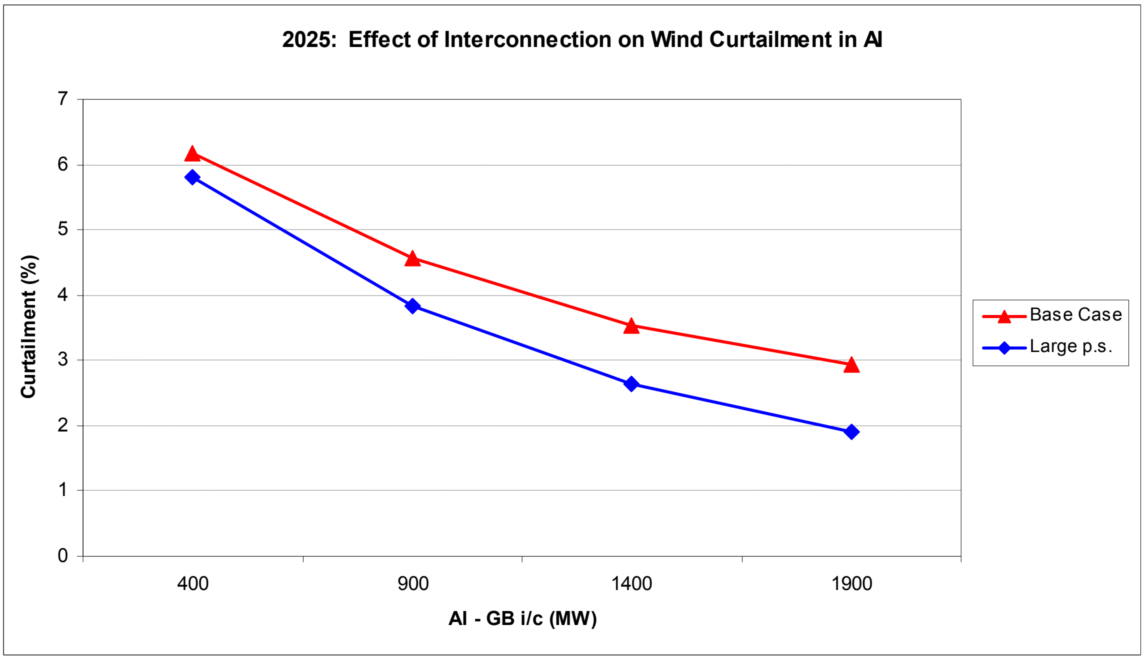

Figure 5.32 New pumped storage: Effect of Interconnection on Wind Curtailment in 2025.

5.3.2.3 Flows from AI to GB

Figure 5.33 shows the annual flow energy values for the different interconnection capacity assumptions. The flows in each direction are shown as well as the net flow. As can be seen, the predominant flow is from GB to AI.

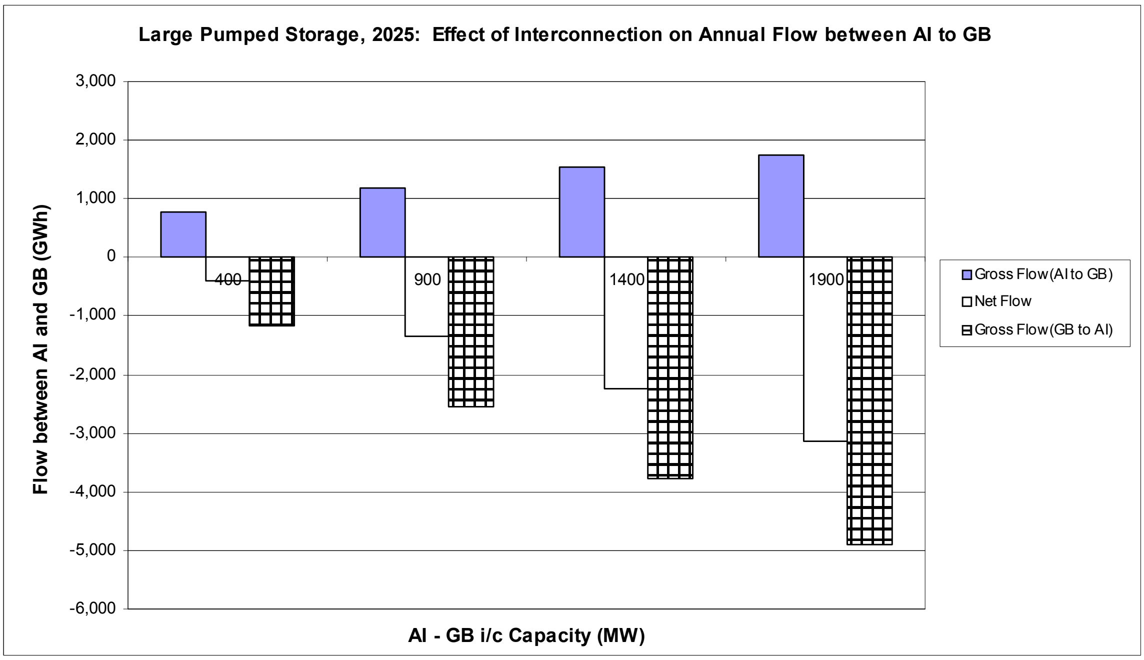

Figure 5.33 New pumped storage: Effect of Interconnection Capacity on Flow in 2025.

Considering only the net flows, the GWh values were converted to MW giving the average hourly net flow. Figure 5.34 shows the values for the different interconnection capacity assumptions, along with results from the Base Case.

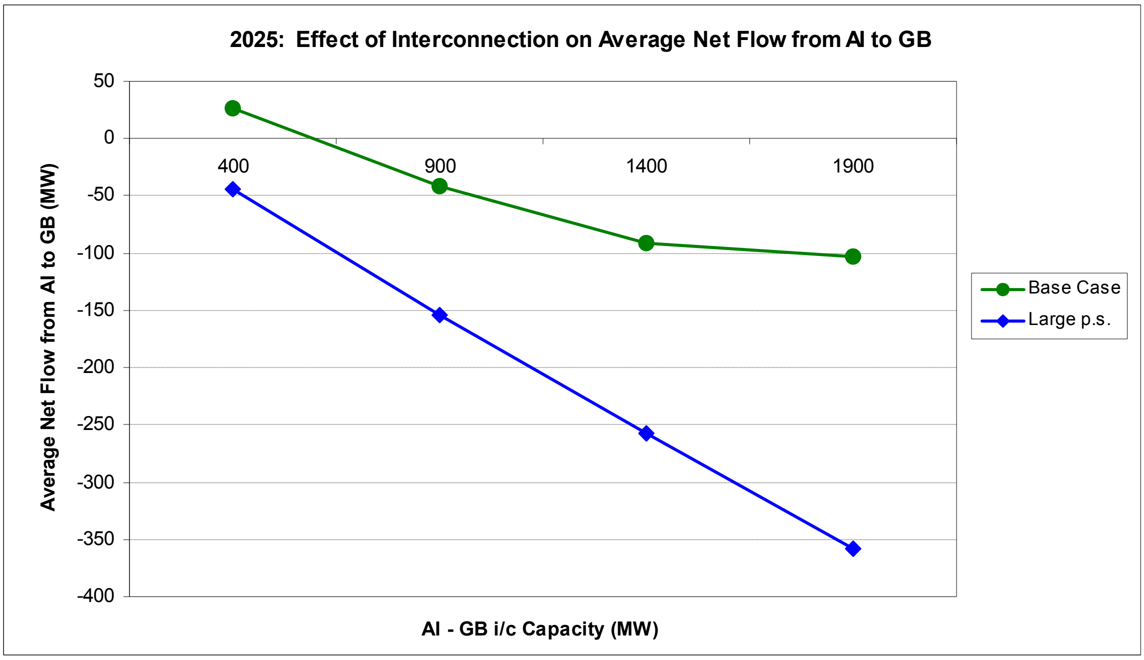

Figure 5.34 New pumped storage: Effect of Interconnection on Average Hourly Net Flow (2025).

Figure 5.35 shows the capacity factors for the different interconnection capacity assumptions. Results are repeated from the Base Case for comparison purposes. As can be seen, the capacity factors are similar for the two scenarios.

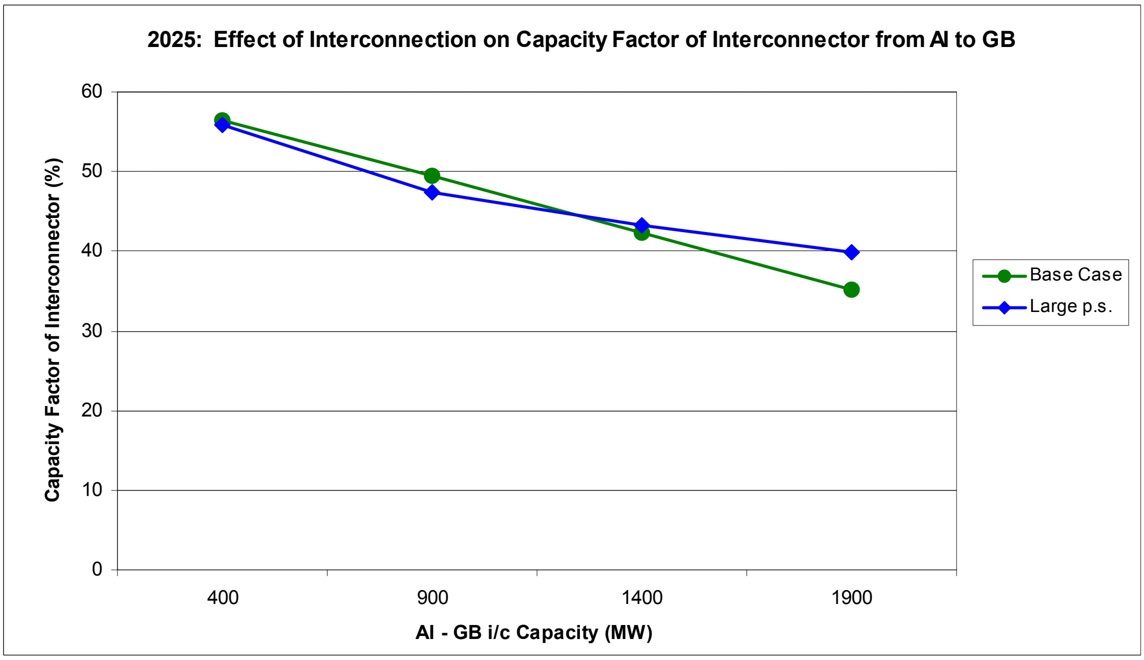

Figure 5.35 New pumped storage: Effect of Capacity on Capacity Factor of Interconnector.

5.3.2.4 CO2 Emissions

CO_2 Emissions in AI are reduced by interconnection with GB – see Figure 5.36 below. The results from the Base Case are repeated for comparison purposes.

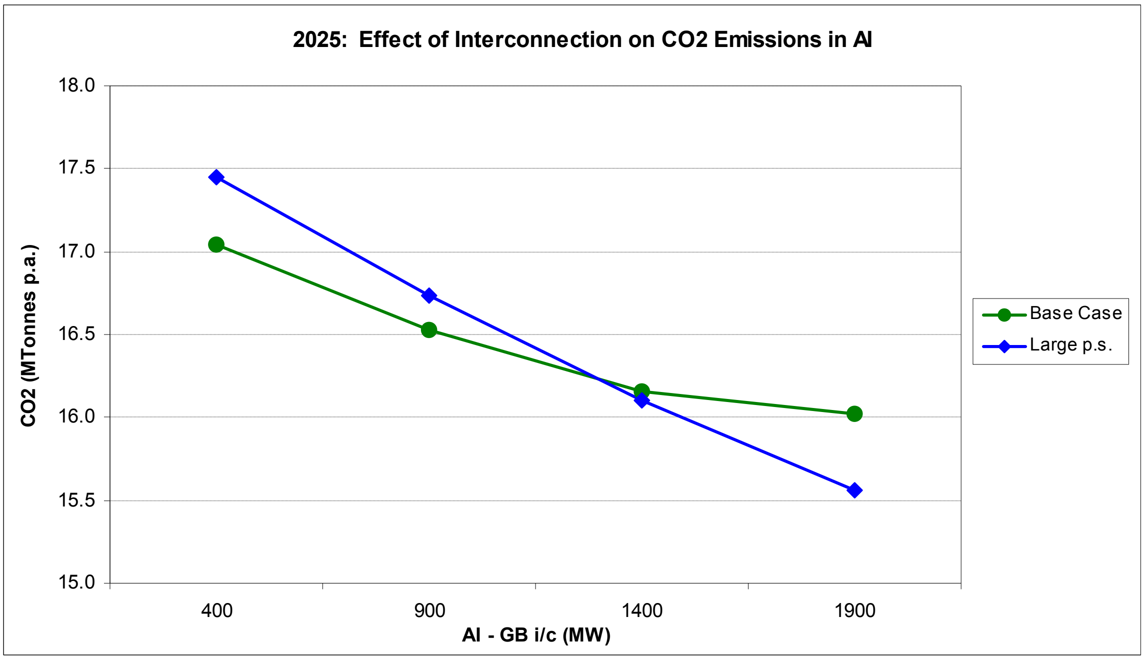

Figure 5.36 New pumped storage: Effect of Interconnection Capacity on CO_2 Emissions in AI.

Figure 5.37 shows the relative effect on CO_2 emissions of increasing interconnection (the 400MW case is the reference point):

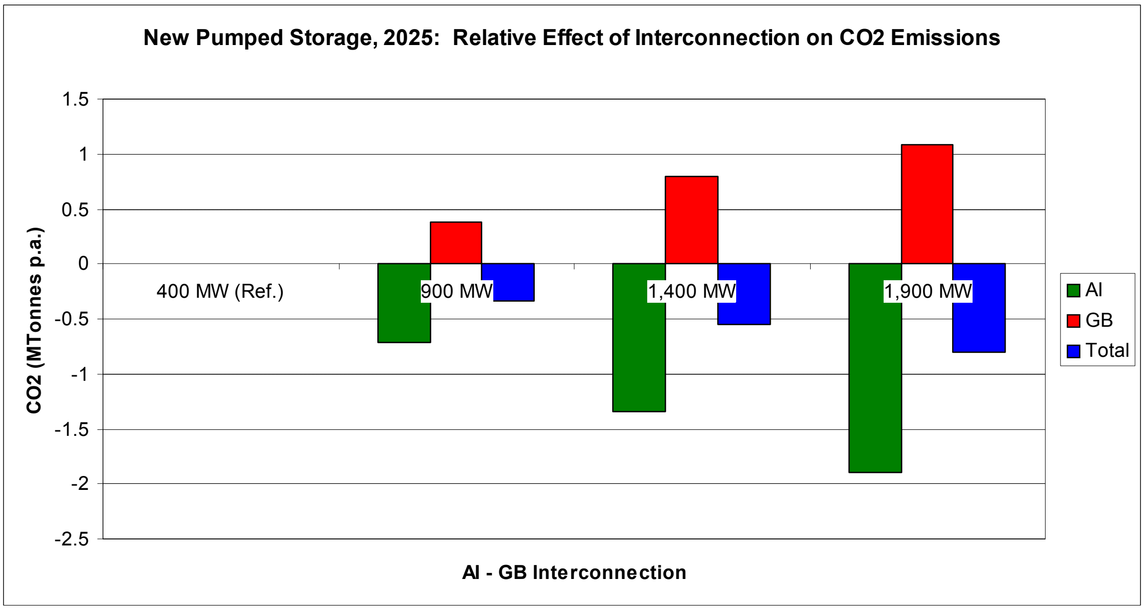

Figure 5.37 New pumped storage, 2025: Relative Effect of Interconnection on CO_2 in AI and GB.

5.3.2.5 System Marginal Price (SMP)

Figure 5.38 shows the effect of interconnection on SMP in AI and GB for the large pumped storage station scenario. The Base Case values are also shown for comparison purposes. In comparison to the Base Case, the SMP values for the large pumped storage station scenario are higher in AI, and slightly higher in GB.

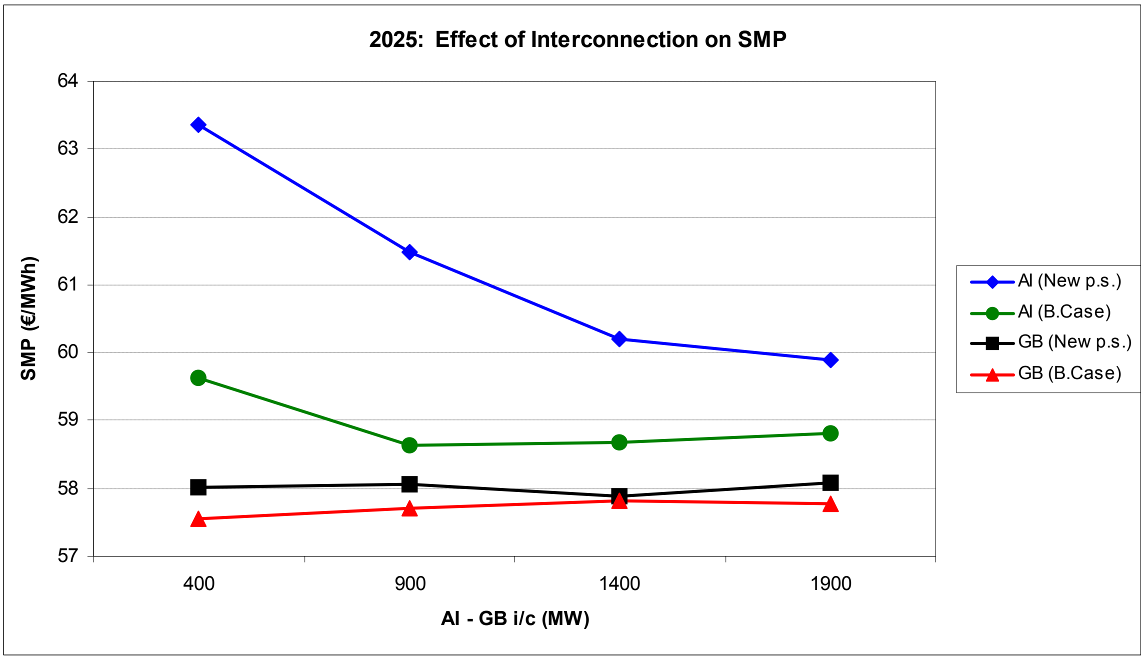

Figure 5.38 Effect of Interconnection on SMP in 2025 (Base Case and large pumped storage station scenario).

5.3.2.6 Congestion Rent

Applying the SMPs as a proxy market price, the congestion rents detailed in Table 5.7 apply for the AI-GB interconnector under the large pumped storage station scenario. Results from the Base Case are repeated for comparison purposes. As can be seen, the presence of the large pumped storage station reduces the congestion rent relative to the Base Case.

Capacity of AI - GB i/c	€M / year		€ / (kW x year)	
	Base Case	Large Pumped Storage	Base Case	Large Pumped Storage
400 MW	32	24	79	59
900 MW	37	26	41	29
1,400 MW	28	17	20	12
1,900 MW	18	9	10	5

Table 5.7 Congestion Rent for the Base Case and large pumped storage scenarios.

5.3.3 Sensitivity Study 3: OCGTs added to AI system in 2020 and 2025

Four additional 93MW OCGTs were added to the AI system by 2020 (relative to the 2020 Base Case). A 415MW CCGT unit was decommissioned to accommodate them. Twelve additional 93MW OCGTs were added to the AI system by 2025 (relative to the 2025 Base Case). Three 415MW CCGT units were decommissioned in 2025 to accommodate them.

5.3.3.1 Benefit: Reduction in Total System Production Cost

Considering the AI and GB systems together, the benefits associated with increasing interconnection between AI and GB are detailed in Table 5.8. Results from the Base Case are repeated for comparison purposes. As can be seen, the presence of the OCGTs on the AI system increases the savings from AI–GB interconnection.

Benefit (€M p.a.)	Base Case		Sensitivity Study 3	
	2020	2025	2020	2025
AI - GB i/c: from 400 to 900 MW	43	50	47	65
AI - GB i/c: from 900 to 1,400 MW	25	27	28	42
AI - GB i/c: from 1,400 to 1,900 MW	14	12	16	25

Table 5.8 Additional OCGTs: Reduction in total system production cost.

5.3.3.2 Wind Curtailment in AI

The OCGTs have the same effect on wind curtailment as the Base Case in both 2020 and 2025. The results are shown in Figure 5.39 along with the results from the Base Case (repeated for comparison purposes).

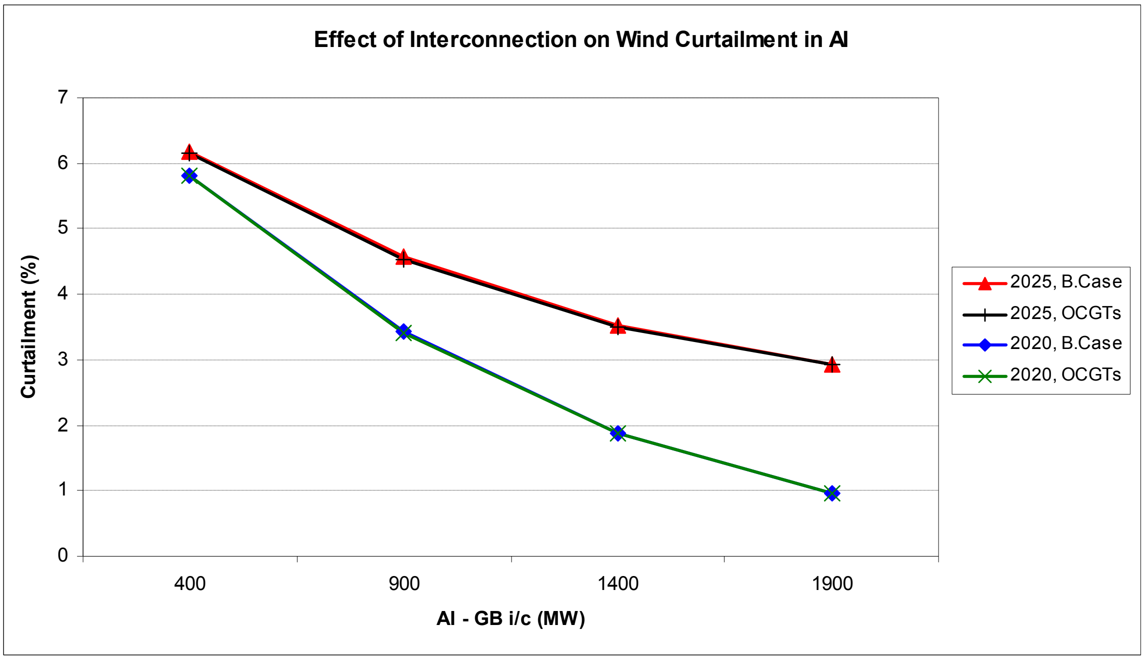

Figure 5.39 Additional OCGTs: Effect of Interconnection on Wind Curtailment in 2020 and 2025.

5.3.3.3 Flows from AI to GB

Figures 5.40 and 5.41 show the net interconnector flows for the different interconnection capacity assumptions. The Base Case values are shown for comparison purposes. The OCGTs increase flows from GB to AI relative to the Base Case.

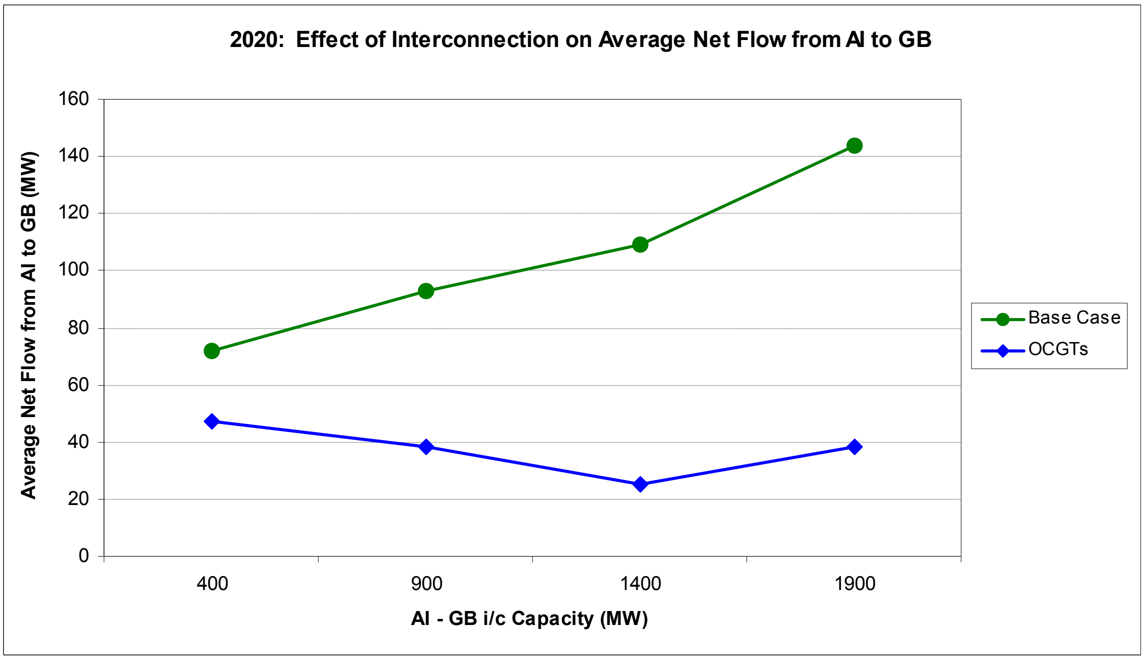

Figure 5.40 Additional OCGTs: Effect of Interconnection Capacity on Average Net Flow in 2020.

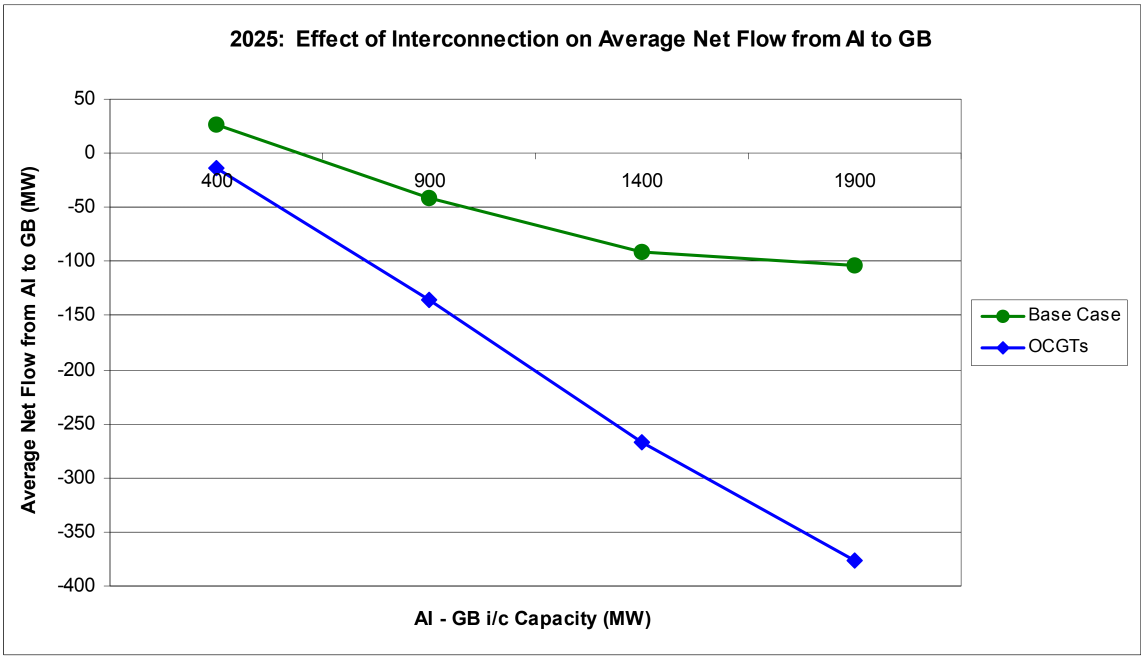

Figure 5.41 Additional OCGTs: Effect of Interconnection Capacity on Average Net Flow in 2025.

Figures 5.42 and 5.43 show the capacity factors in 2020 and 2025 for the different interconnection capacity assumptions. Results from the Base Case are repeated for comparison purposes. The OCGT scenario shows slightly more utilisation relative to the Base Case.

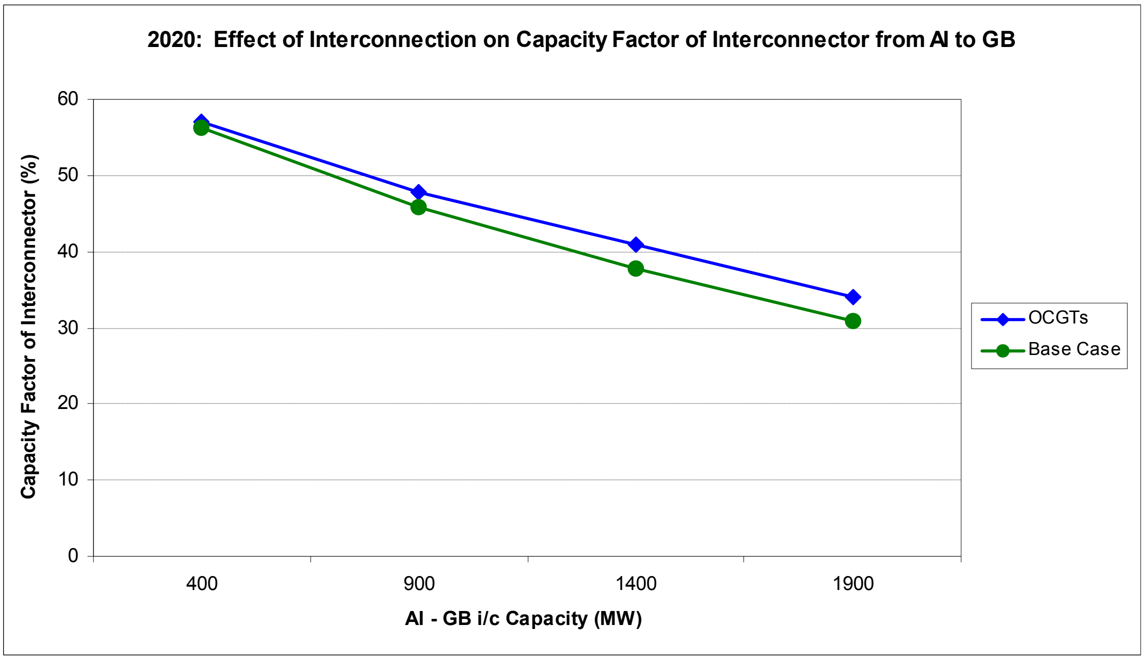

Figure 5.42 Additional OCGTs: Effect of Capacity on Capacity Factor in 2020.

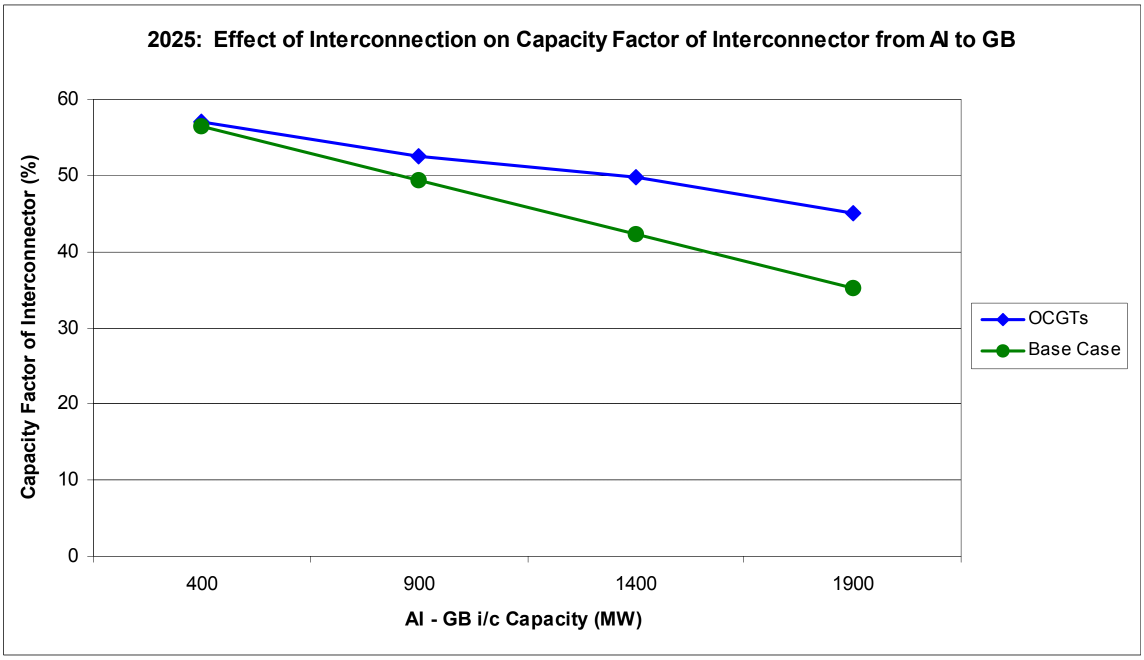

Figure 5.43 Additional OCGTs: Effect of Capacity on Capacity Factor in 2025.

5.3.3.4 CO2 Emissions

With increased interconnection, CO_2 emissions in AI are reduced for the additional OCGTs scenario – see Figure 5.44 below. The results from the Base Case are repeated for comparison purposes.

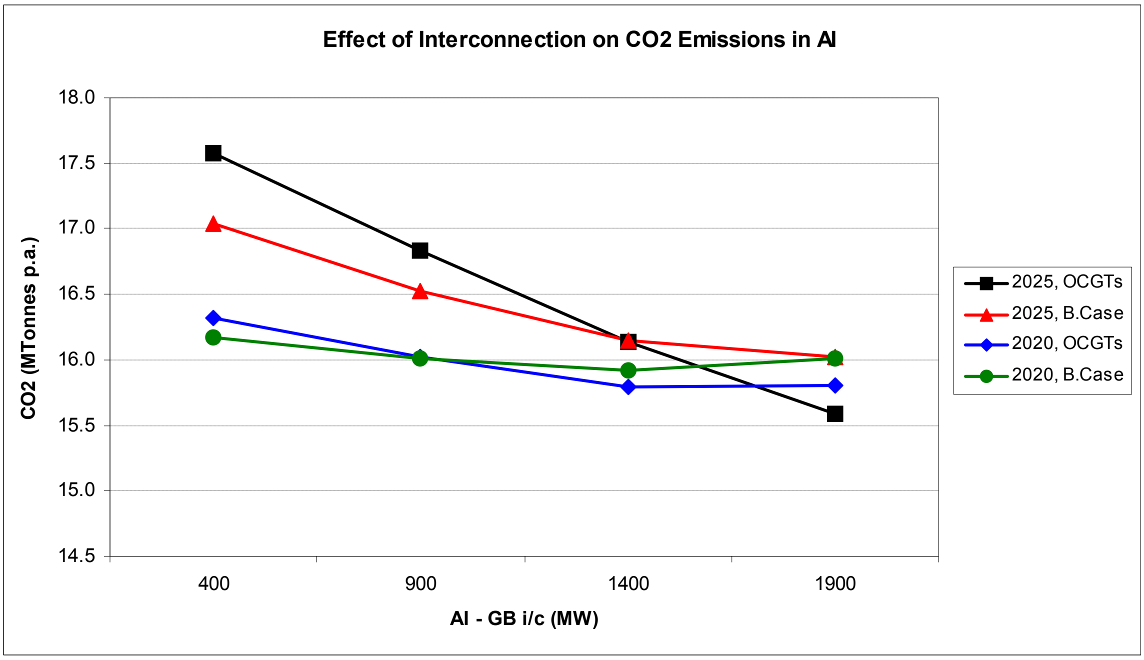

Figure 5.44 Additional OCGTs: Effect of Interconnection Capacity on CO_2 Emissions in AI.

Figures 5.45 and 5.46 show the relative effect on CO_2 emissions of increasing interconnection for the additional OCGTs scenario (the 400MW case is the reference point).

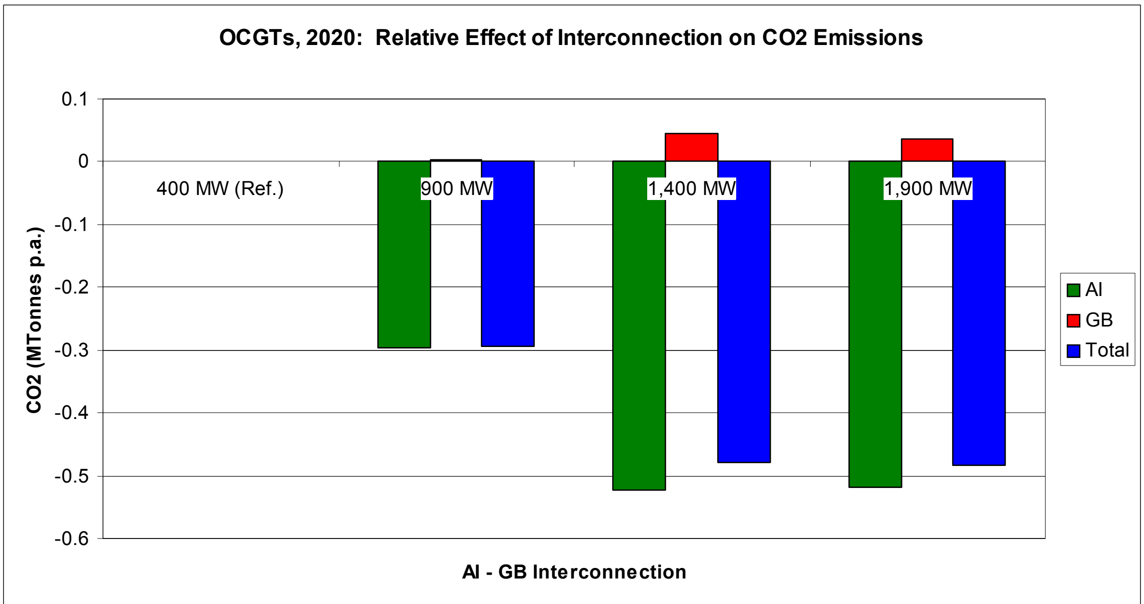

Figure 5.45 Additional OCGTs, 2020: Relative Effect of Interconnection on CO_2 in AI and GB.

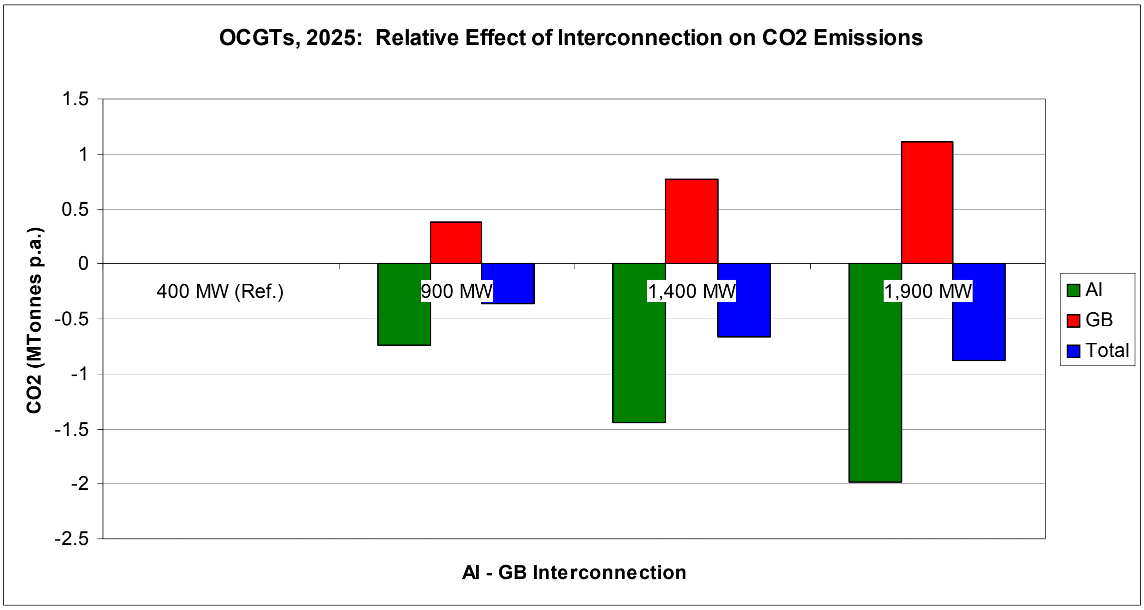

Figure 5.46 Additional OCGTs, 2025: Relative Effect of Interconnection on CO_2 in AI and GB.

5.3.3.5 System Marginal Price (SMP)

Figures 5.47 and 5.48 show the effect of interconnection on SMP in AI and GB for the additional OCGTS scenario, for the years 2020 and 2025. The Base Case values are also shown for comparison purposes. The trend for the additional OCGTs scenario is very similar to the Base Case; the values for the OCGT studies are higher.

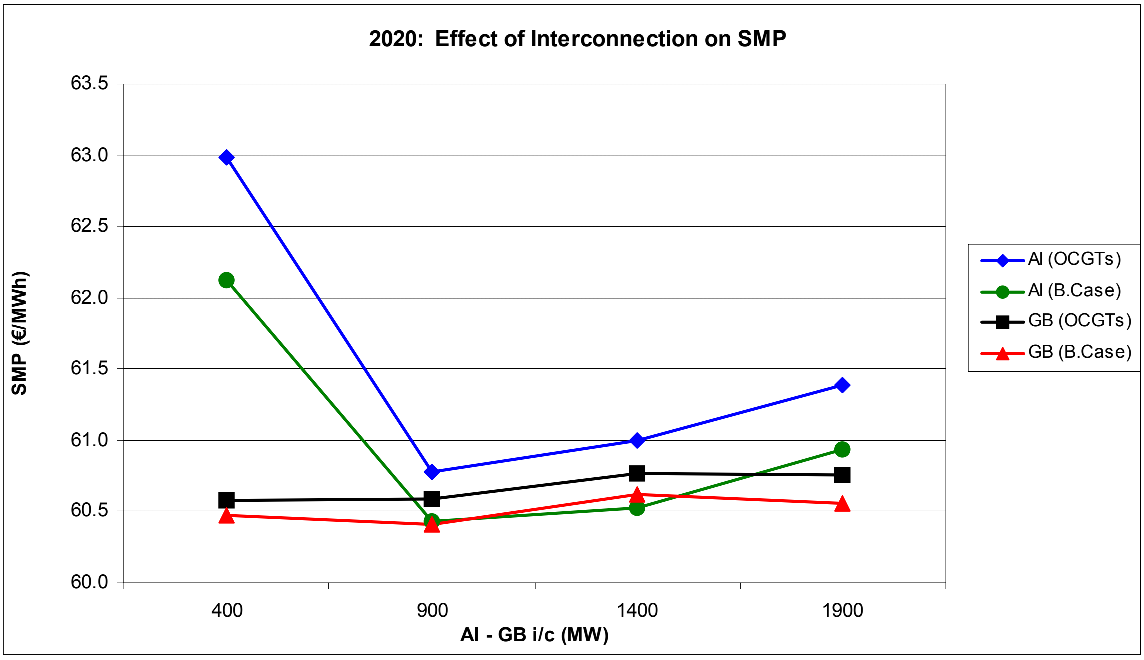

Figure 5.47 Effect of Interconnection on SMP in 2020 (Base Case and additional OCGTs scenario).

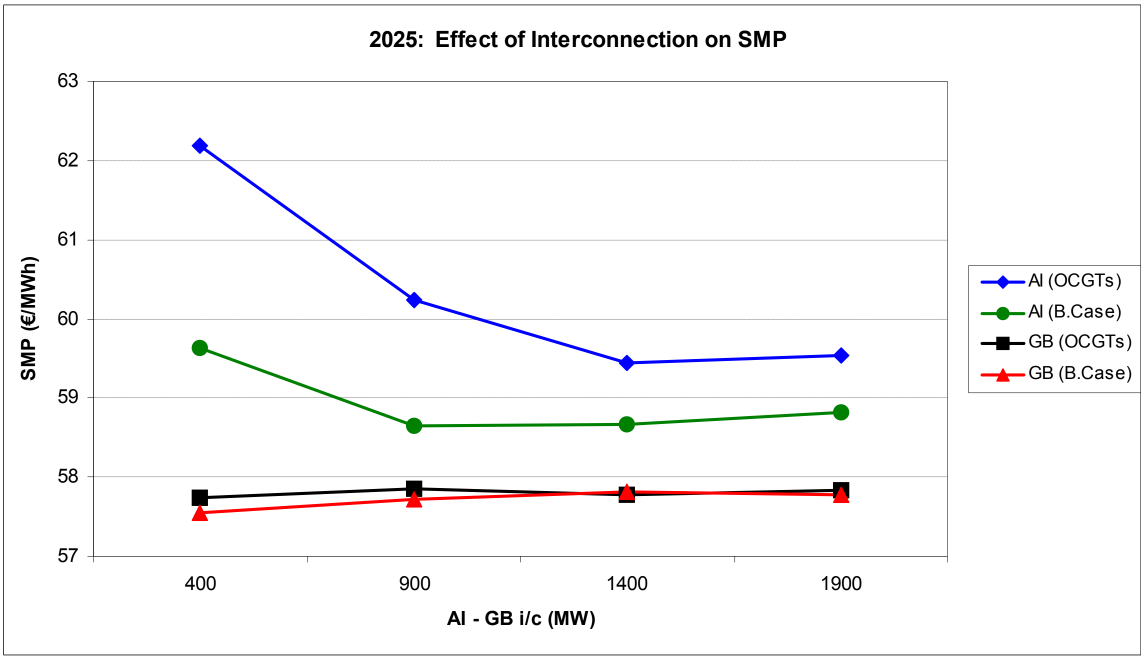

Figure 5.48 Effect of Interconnection on SMP in 2025 (Base Case and additional OCGTs scenario).

5.3.3.6 Congestion Rent

Applying the SMPs as a proxy market price, Tables 5.9 and 5.10 show the congestion rents which apply for the AI-GB interconnector under the additional OCGTs scenario. Results from the Base Case are repeated for comparison purposes.

Capacity of AI - GB i/c	Base Case (€M / year)		OCGTs (€M / year)	
	2020	2025	2020	2025
400 MW	36	32	37	37
900 MW	39	37	39	43
1,400 MW	31	28	31	33
1,900 MW	21	18	13	22

Table 5.9 Congestion Rent in €M / year (Base Case and additional OCGTs scenario).

Capacity of AI - GB i/c	Base Case (€ / (kW x year))		OCGTs (€ / (kW x year))	
	2020	2025	2020	2025
400 MW	89	79	92	93
900 MW	44	41	43	48
1,400 MW	22	20	22	23
1,900 MW	11	10	7	11

Table 5.10 Congestion Rent in € / (kW x year) (Base Case and additional OCGTs scenario).

5.3.4 Sensitivity Study 4: High wind scenario on AI system in 2025

8,000 MW of wind was assumed to be installed in the RoI system in 2025. The Base Case assumed 5,845 MW, i.e. 2,155 MW less.

5.3.4.1 Benefit: Reduction in Total System Production Cost

Considering the All-island (AI) and GB systems together, the following benefits are associated with increasing interconnection between AI and GB. Results are repeated from the Base Case, for comparison purposes.

Benefit (€M p.a.)	Base Case	Sensitivity Study 4
AI - GB i/c: from 400 to 900 MW	50	73
AI - GB i/c: from 900 to 1,400 MW	27	50
AI - GB i/c: from 1400 to 1900 MW	12	32

Table 5.11: High Wind: Reduction in total system production cost.

The benefits of interconnection are larger for the high wind scenario. Both sets of studies show a decreasing benefit from extra interconnection.

5.3.4.2 Wind Curtailment in AI

The high wind scenario increases the scope for benefit from interconnection. The results are given in Figure 5.49 below, along with results from the Base Case (repeated for comparison purposes).

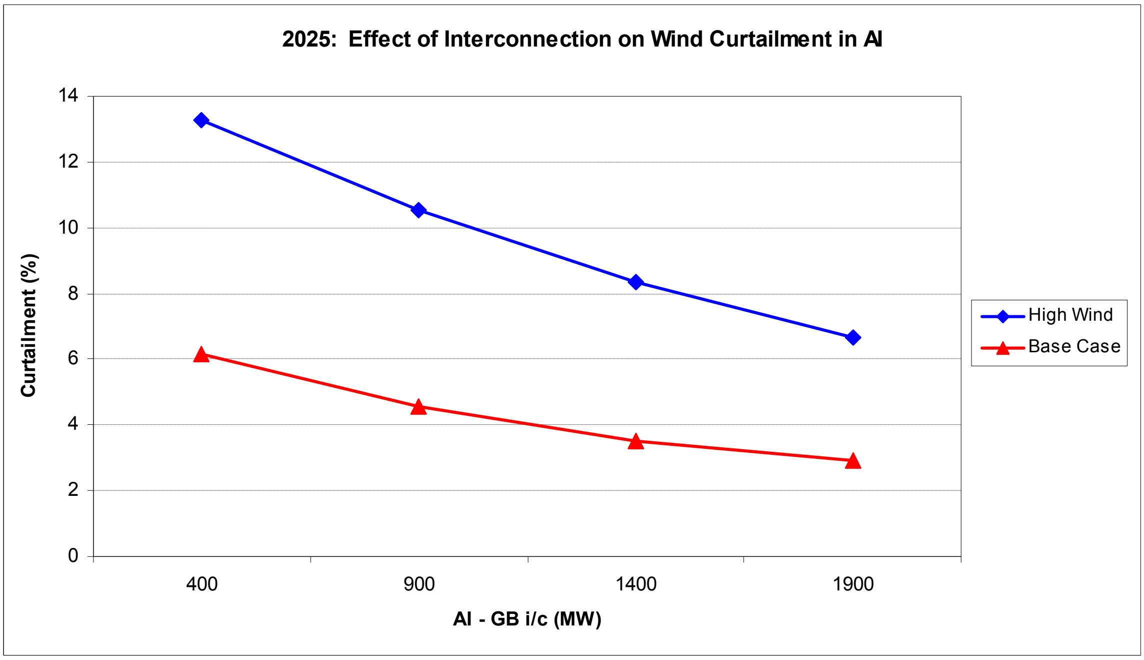

Figure 5.49 High Wind: Effect of Interconnection on Wind Curtailment in 2025.

5.3.4.3 Flows from AI to GB

The following graph (Figure 5.50) shows the annual energy values for the different interconnection capacity assumptions. The flows in each direction are given, as well as the net flow. The predominant net flow is from AI to UK.

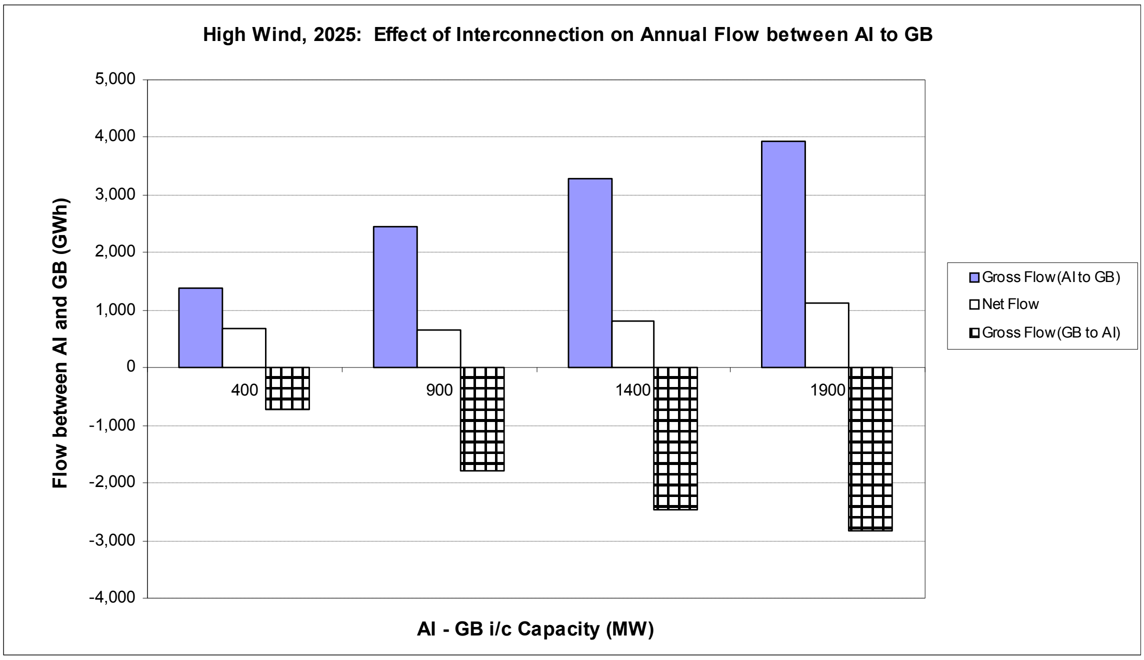

Figure 5.50 High Wind: Effect of Interconnection Capacity on Flow between AI to GB in 2025.

Considering only the net flows, the GWh values were converted to MW giving the average hourly net flow. The following graph (Figure 5.51) shows the values for the different interconnection capacity assumptions, along with results from the Base Case (repeated for comparison purposes).

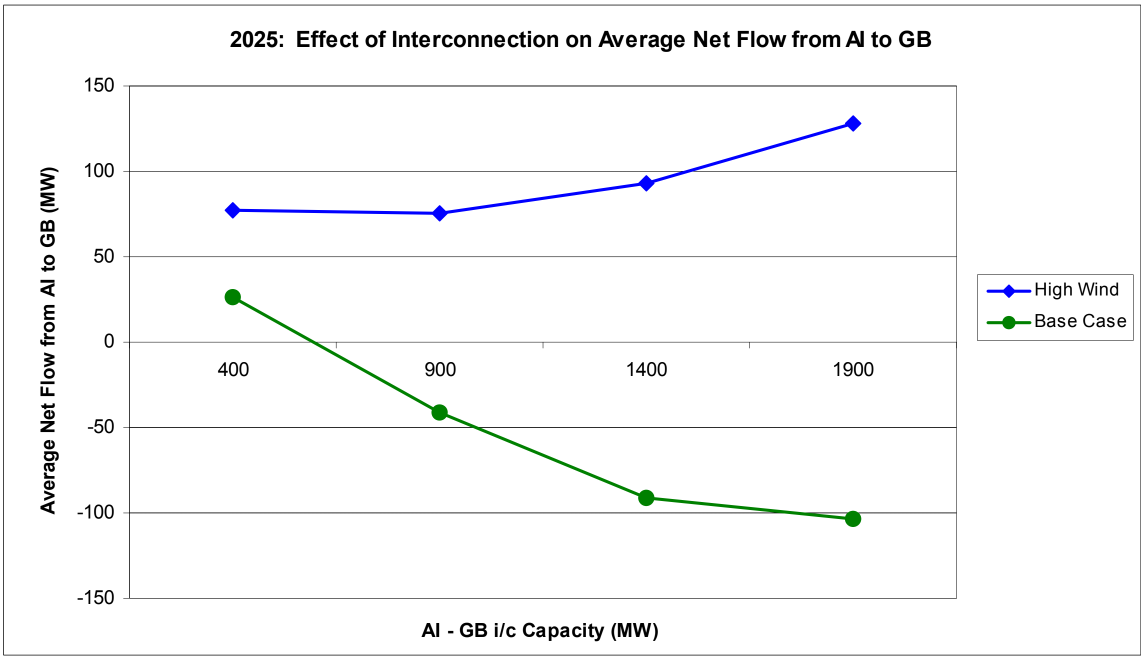

Figure 5.51 High Wind: Effect of Interconnection Capacity on Average Net Flow in 2025.

The following graph (Figure 5.52) shows the capacity factors for the different interconnection capacity assumptions. Results are repeated from the Base Case, for comparison purposes. The High Wind scenario shows greater utilisation.

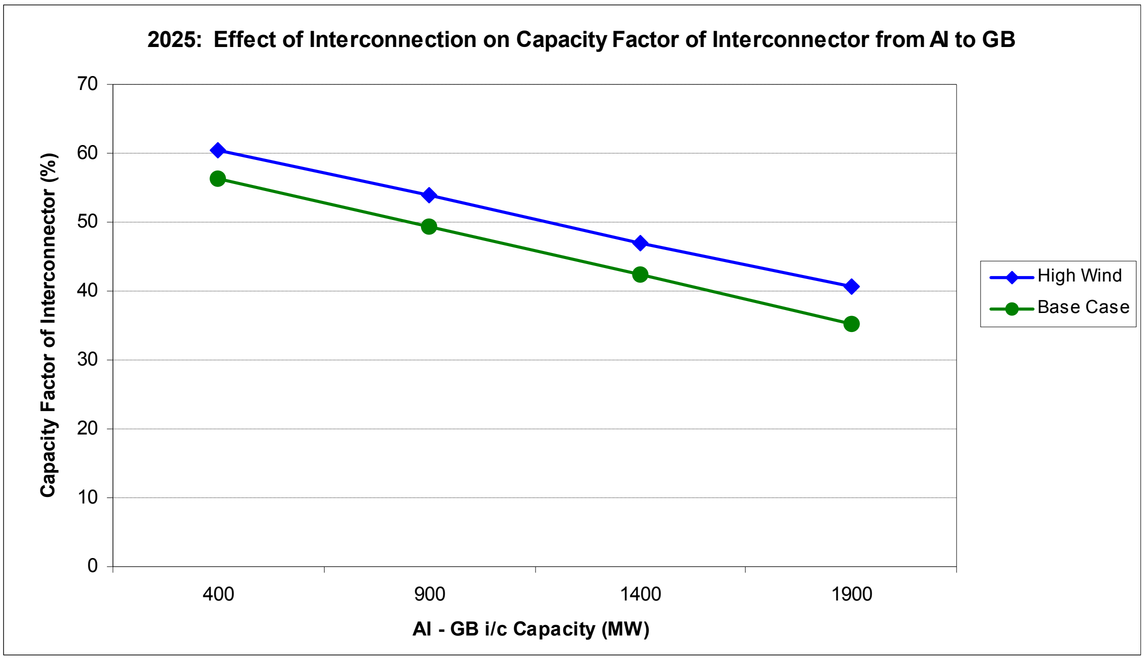

Figure 5.52 High Wind: Effect of Capacity on Capacity Factor of Interconnector.

5.3.4.4 CO2 Emissions

CO2 Emissions in AI are reduced by interconnection with GB – see Figure 5.53 below. The results from the Base Case are repeated for comparison purposes. In the high wind scenario, CO2 is reduced compared to the Base Case.

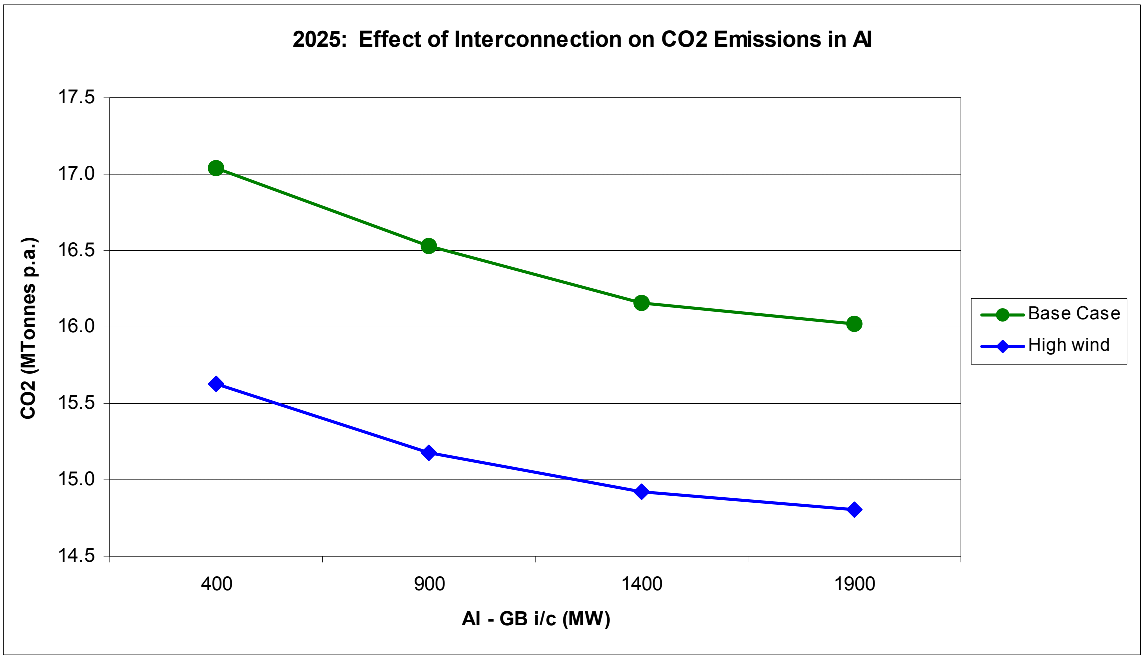

Figure 5.53 High Wind: Effect of Interconnection Capacity on CO2 Emissions in AI.

The following graph (Figure 5.54) shows the relative effect on CO2 emissions of increasing interconnection (the 400MW case is the reference point):

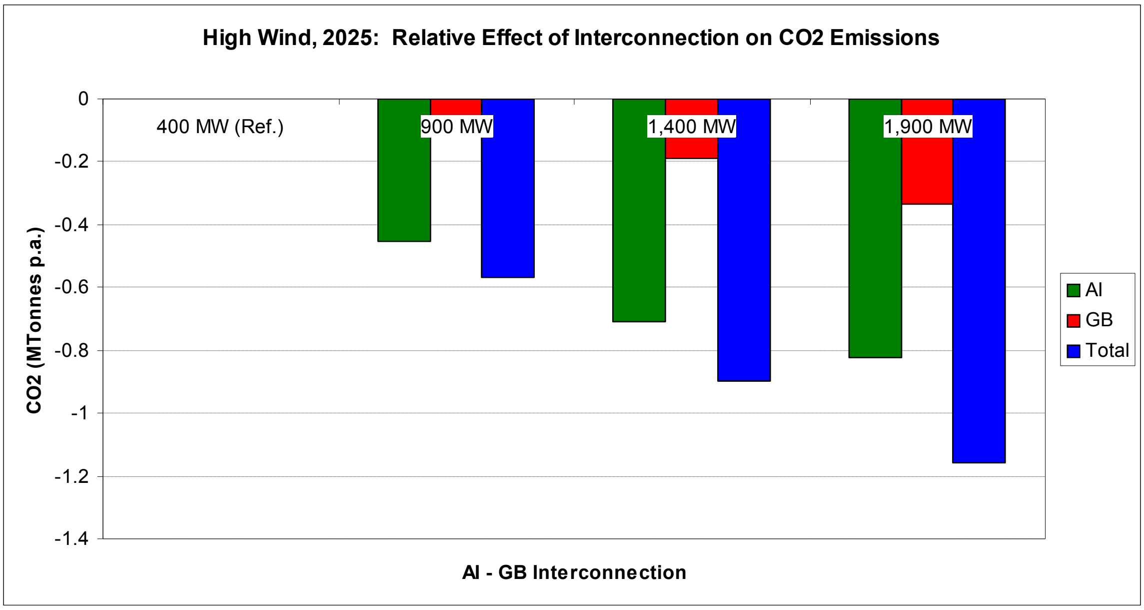

Figure 5.54 High Wind, 2025: Relative Effect of Interconnection on CO2 in AI and GB.

5.3.4.5 System Marginal Price (SMP)

The graph below (Figure 5.55) shows the effect of interconnection on SMP. The Base Case values are shown for comparison purposes. The values for the high wind studies are much lower in AI.

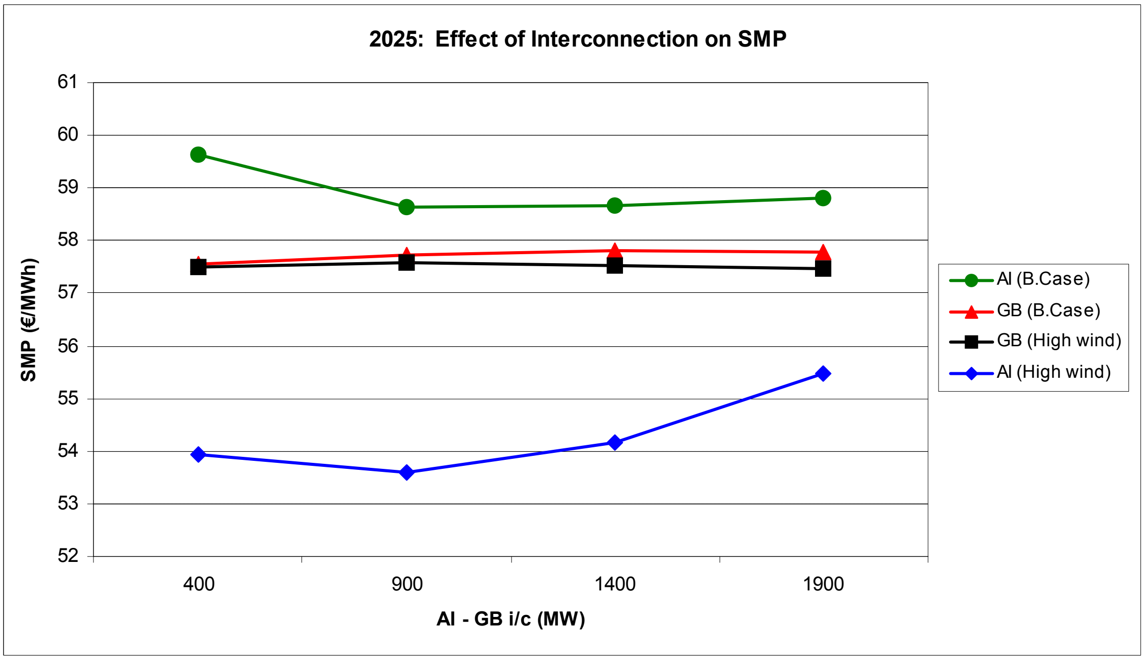

Figure 5.55 Effect of Interconnection on SMP in 2025 (Base Case and high wind study).

5.3.4.6 Congestion Rent

Applying the SMPs as a proxy market price, the following congestion rents apply for the AI-GB interconnector – see Table 5.12. Results are repeated from the Base Case, for comparison purposes.

Capacity of AI - GB i/c	€M / year		€ / (kW x year)	
	Base Case	High Wind	Base Case	High Wind
400 MW	32	44	80	111
900 MW	37	69	41	76
1,400 MW	28	77	20	55
1,900 MW	18	74	9	39

Table 5.12: Congestion Rent (Base Case and High Wind).

The high wind scenario increases the congestion rent.

5.3.5 Sensitivity Study 5: New coal plant added to AI system in 2025

Four new 389MW coal units were added to the AI system by 2025. Three 415MW CCGT units and the three Moneypoint units were decommissioned to accommodate them. Five OCGTs were also added to maintain system adequacy.

5.3.5.1 Benefit: Reduction in Total System Production Cost

Considering the All-island (AI) and GB systems together, the following benefits are associated with increasing interconnection between AI and GB. Results are repeated from the Base Case, for comparison purposes.

Benefit (€M p.a.)	Base Case	Sensitivity Study 5
AI - GB i/c: from 400 to 900 MW	50	59
AI - GB i/c: from 900 to 1400 MW	27	35
AI - GB i/c: from 1400 to 1900 MW	12	17

Table 5.13: New Coal Units: Reduction in total system production cost.

The presence of the new coal plant on the AI system increases the savings from the AI – GB interconnector.

5.3.5.2 Wind Curtailment in AI

The new coal station causes a slight increase in wind curtailment. The results are given in Figure 5.56 below, along with results from the Base Case (repeated for comparison purposes).

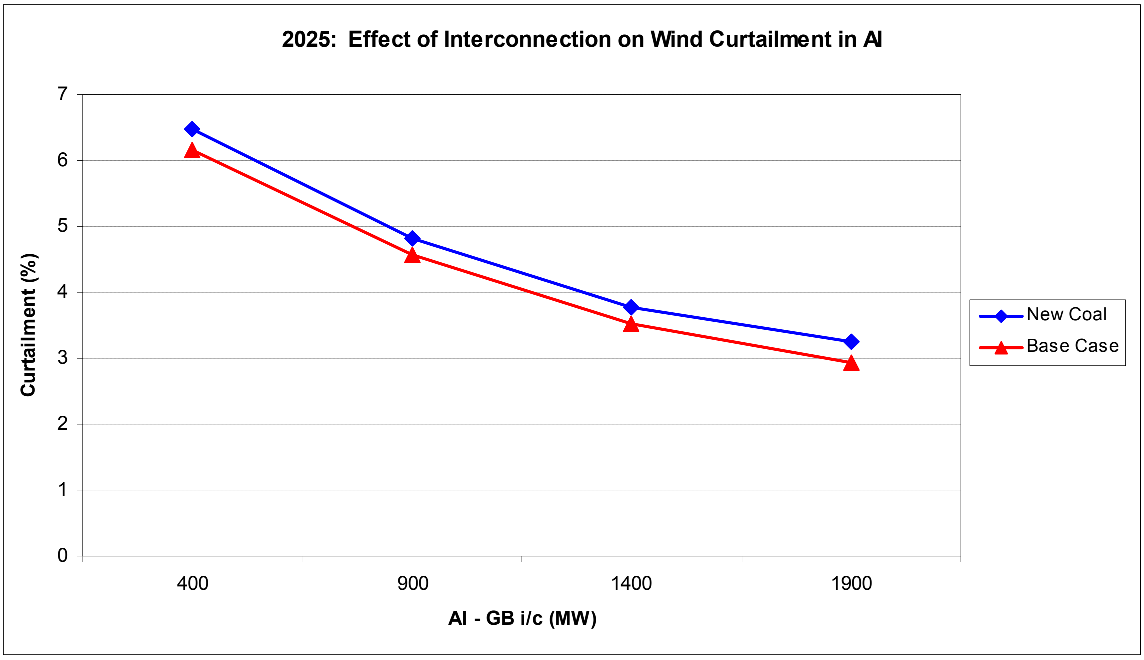

Figure 5.56 New Coal: Effect of Interconnection on Wind Curtailment in 2025.

5.3.5.3 Flows from AI to GB

The following graph (Figure 5.57) show the annual energy values for the different interconnection capacity assumptions. The flows in each direction are given, as well as the net flow. The predominant flow is from AI to GB.

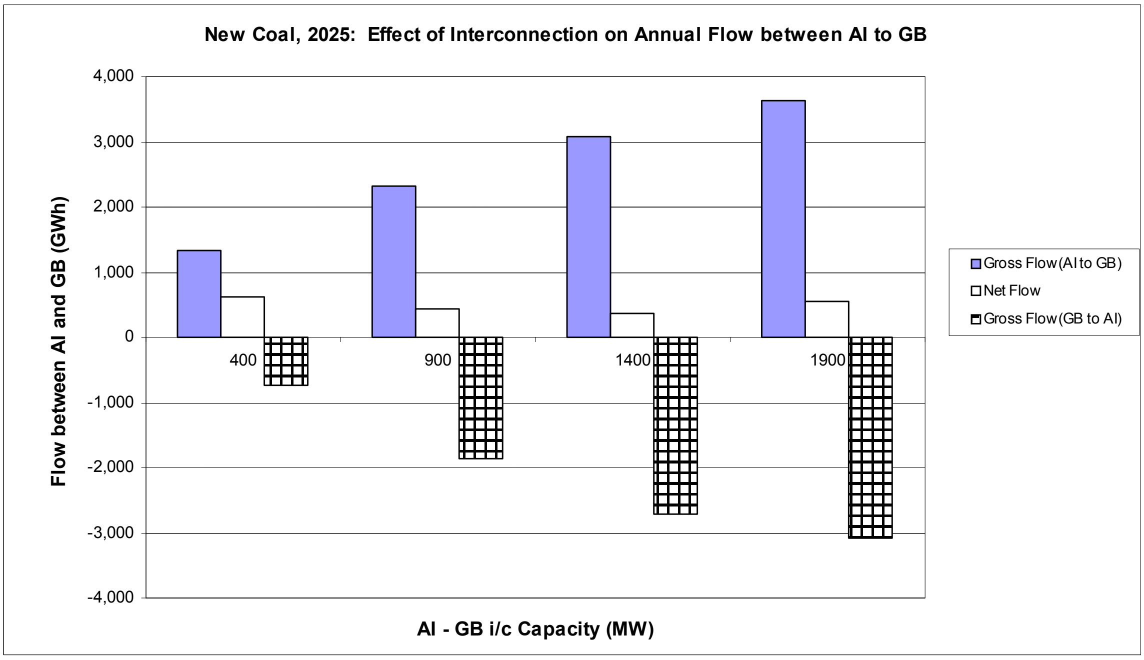

Figure 5.57 New Coal: Effect of Interconnection Capacity on Flow between AI to GB in 2025.

Considering only the net flows, the GWh values were converted to MW giving the average hourly net flow. The following graph (Figure 5.58) shows the values for the different interconnection capacity assumptions, along with results from the Base Case (repeated for comparison purposes). The New Coal scenario produces positive net flows (from AI to GB).

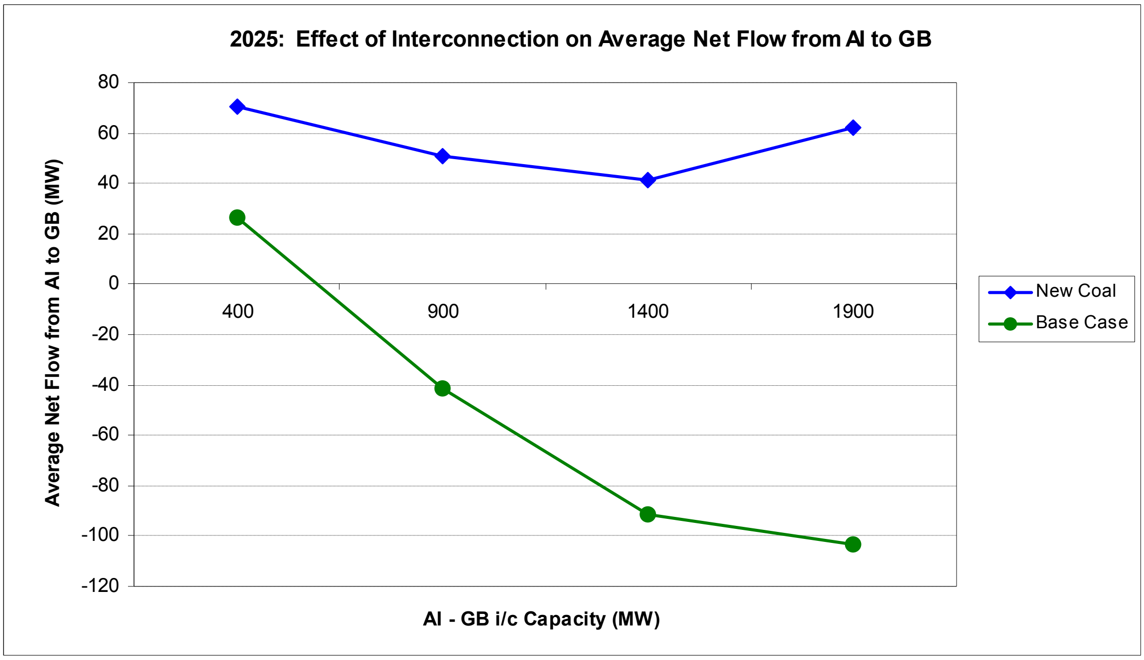

Figure 5.58 New Coal: Effect of Interconnection Capacity on Average Net Flow in 2025.

The following graph (Figure 5.59) shows the capacity factors for the different interconnection capacity assumptions. Results are repeated from the Base Case, for comparison purposes. The New Coal scenario shows slightly greater utilisation.

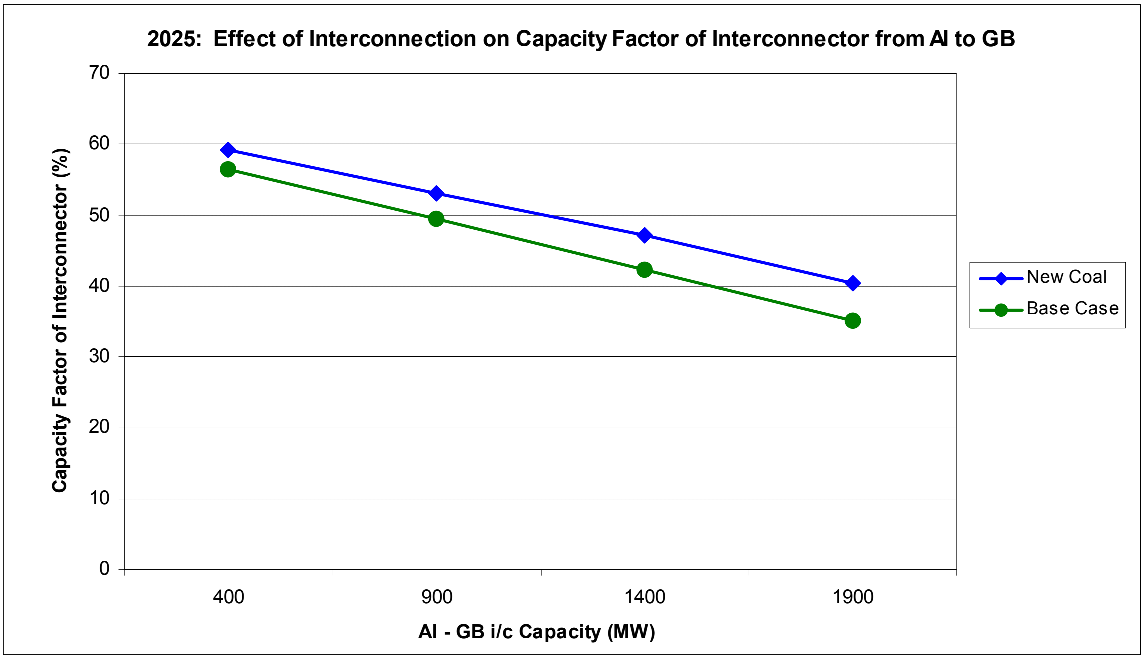

Figure 5.59 New Coal: Effect of Capacity on Capacity Factor of Interconnector.

5.3.5.4 CO2 Emissions

CO2 emissions in AI tend to be reduced by interconnection with GB – see Figure 5.60 below. The results from the Base Case are repeated for comparison purposes. In the new coal scenario, emissions of CO2 are higher compared to the Base Case.

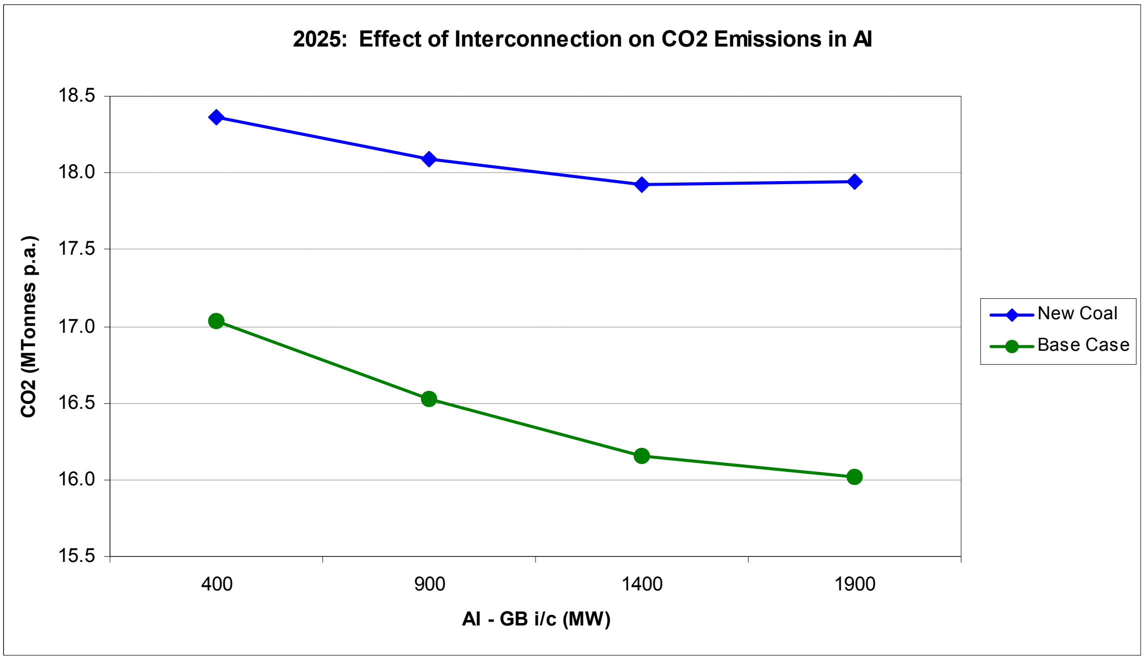

Figure 5.60 New Coal: Effect of Interconnection Capacity on CO2 Emissions in AI.

The following graph (Figure 5.61) shows the relative effect on CO2 emissions of increasing interconnection (the 400MW case is the reference point):

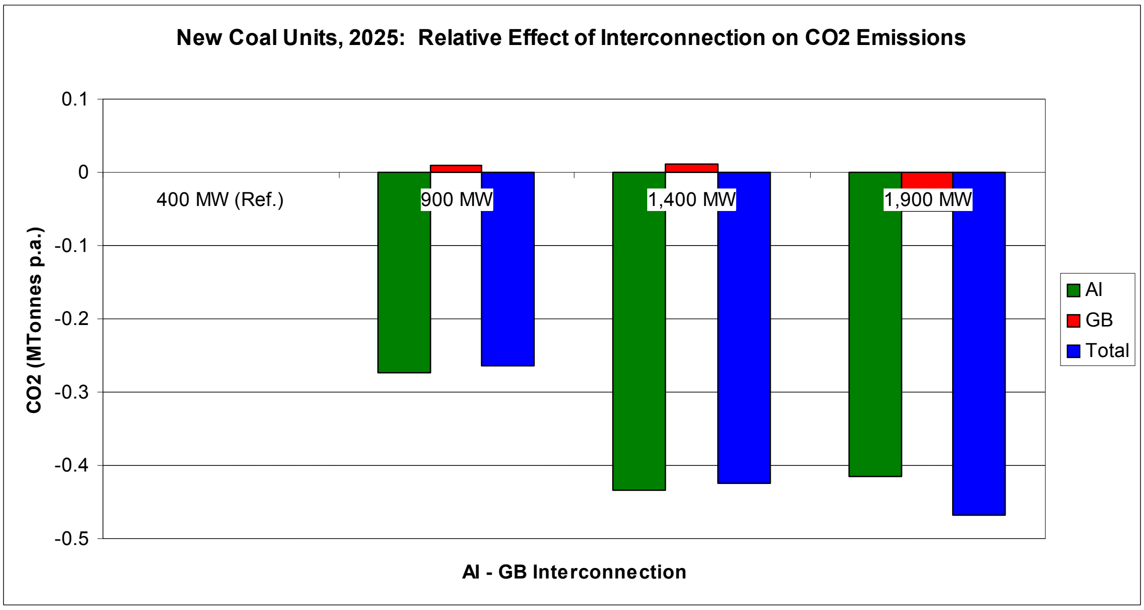

Figure 5.61 New Coal, 2025: Relative Effect of Interconnection on CO2 in AI and GB.

5.3.5.5 System Marginal Price (SMP)

The following graph (Figure 5.62) shows the effect of interconnection on SMP. The Base Case values are shown for comparison purposes. The values for the coal studies are lower in AI.

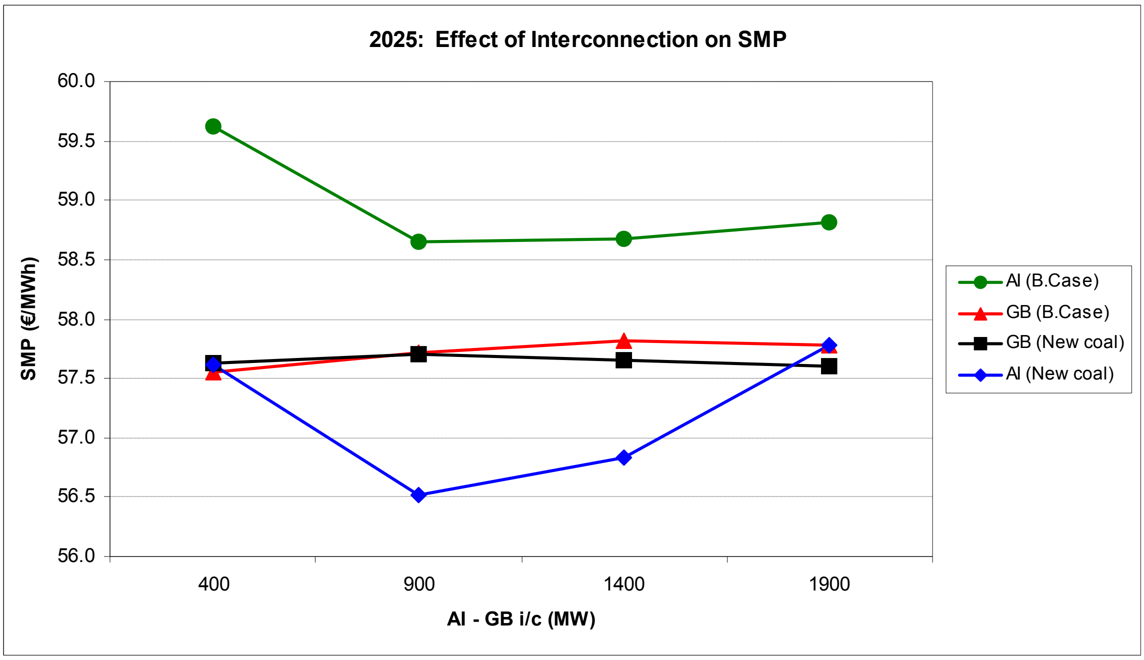

Figure 5.62 Effect of Interconnection on SMP in 2025 (Base Case and new coal study).

5.3.5.6 Congestion Rent

Applying the SMPs as a proxy market price, the following congestion rents apply for the AI-GB interconnector – see Table 5.14. Results are repeated from the Base Case, for comparison purposes.

Capacity of AI - GB i/c	€M / year		€ / (kW x year)	
	Base Case	New Coal	Base Case	New Coal
400 MW	32	37	79	92
900 MW	37	47	41	53
1,400 MW	28	43	20	31
1,900 MW	18	34	10	18

Table 5.14: Congestion Rent (Base Case and New Coal).

5.3.6 Sensitivity Study 6: Interconnector between AI and France

A 500 or 1,000 MW interconnector between AI and France was modelled in 2015, 2020, and 2025. In all cases, the interconnector between AI and GB was assumed to be 900 MW.

This sensitivity study was intended to model flows based on diversity between the two systems. The French system is dominated by nuclear plant, which comprises 57% of the total capacity. This has long been the powerhouse of Northwest Europe, as well as France itself. France is interconnected with Belgium, Germany, Switzerland, Great Britain, Spain and Italy. The ratio of exports from France to imports to France in recent years is about 3:1.

Due to the large number of interconnections, it was considered too onerous to model the French system to the same level of detail as the All-Island (AI) and Great Britain systems. Instead, hourly SRMC price profiles for France were obtained from Ventyx for each of the three study years, and the two fuel price scenarios. These price profiles were input into the model to determine the flows between France and AI.

This sensitivity study indicated high capacity factor for the AI-France interconnector, and corresponding reductions in production cost. However, examining the results at a more detailed level showed factors which were difficult to explain. The problems could be due to the French system being modelled in a less detailed manner than AI, i.e. without a detailed generation portfolio and hourly loads. Accordingly, it was decided not to publish some results. The abridged results shown below should be regarded as tentative only.

5.3.6.1 Benefit: Reduction in Total System Production Cost

The following benefits are associated with increasing interconnection between AI and FR.

Benefit (€M p.a.)	2015	2020	2025
AI - FR i/c: from 0 to 500 MW	38	56	63
AI - FR i/c: from 500 to 1,000 MW	27	37	37

Table 5.15: AI-FR interconnector: Reduction in production cost.

5.3.6.2 Wind Curtailment in AI

Wind curtailment in AI is reduced by interconnection with FR. The following graph (Figure 5.63) shows the effect for the AI system.

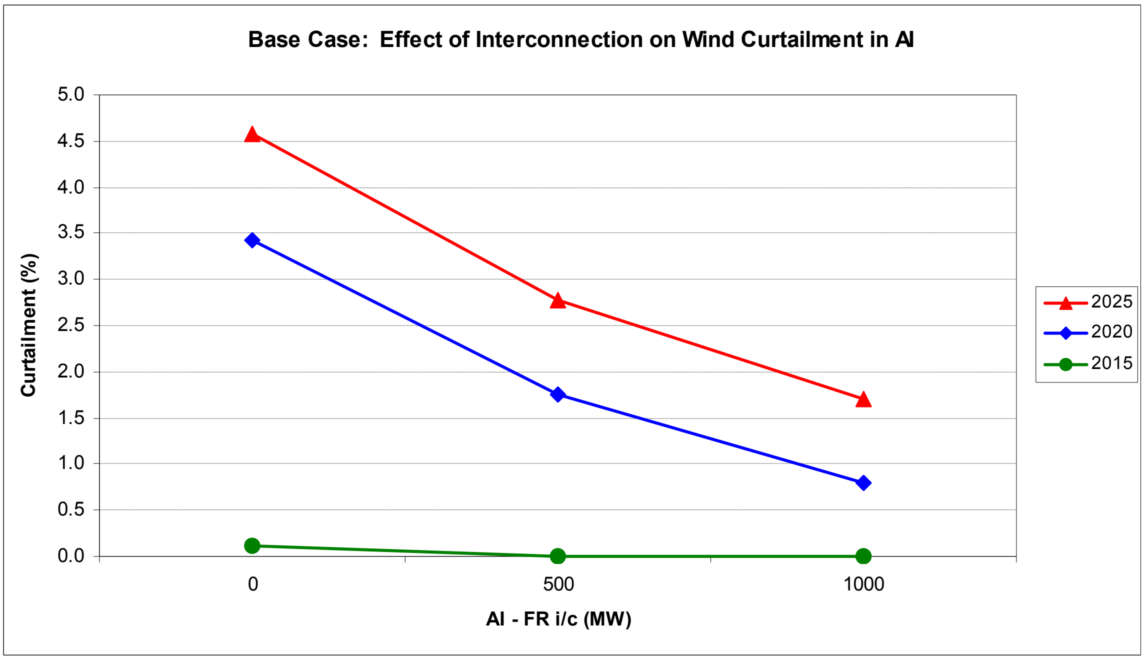

Figure 5.63 AI-FR interconnector: Wind Curtailment in 2015, 2020 and 2025.

5.3.6.3 Capacity Factor of AI-France interconnector

The following graph (Figure 5.64) shows the capacity factors for the different interconnection capacity assumptions.

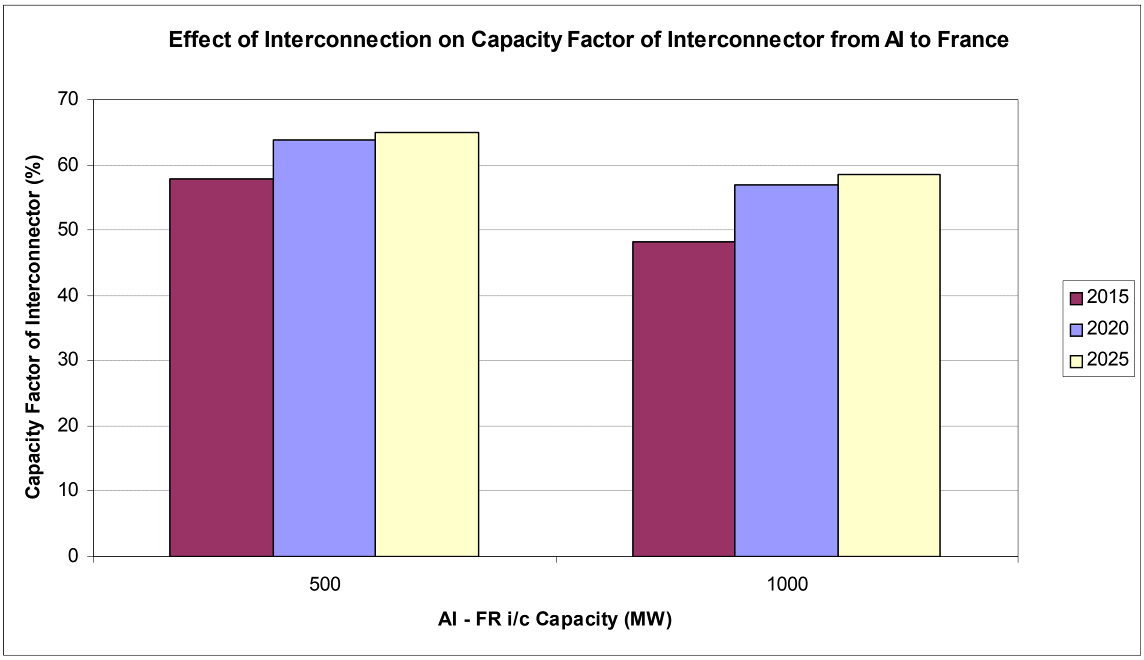

Figure 5.64 AI-FR interconnector: Effect of Interconnection Capacity on Capacity Factor.

5.3.6.4 CO2 Emissions in AI

CO2 emissions in AI are reduced by interconnection in most cases – see Figure 5.65. The CO2 decrease from 2015 to 2020 seems to be driven by extra wind generation in that period. The CO2 increase from 2020 to 2025 is probably related to growth in demand, and the relatively small amount of extra wind.

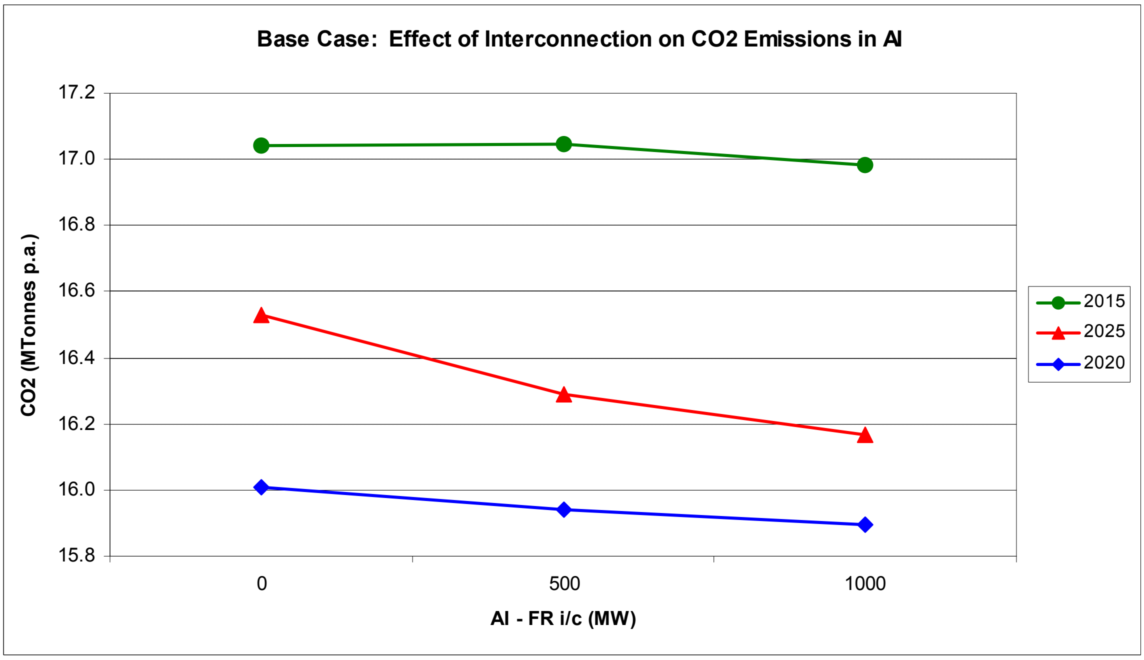

Figure 5.65 AI-FR interconnector: Effect of Interconnection on CO2 Emissions in AI.

5.4 Summary of Results for 2025

The Base Case and the five AI-GB sensitivity studies are summarised here for the year 2025 (when all sensitivity studies were analysed). The following results are examined in turn:

- Reduction in total system production cost in AI+GB;
- Wind Curtailment in AI;
- Net Flows from AI to GB;
- Capacity Factor of AI-GB Interconnector
- CO_2 Emissions in AI
- System Marginal Price (SMP);
- Congestion Rent.

5.4.1 Reduction in Total System Production Cost in AI+GB

One of the benefits of interconnection is the Reduction in total system production cost. Considering the All-island (AI) and GB systems together, the following graph (Figure 5.66) shows the benefits associated with increasing interconnection between AI and GB.

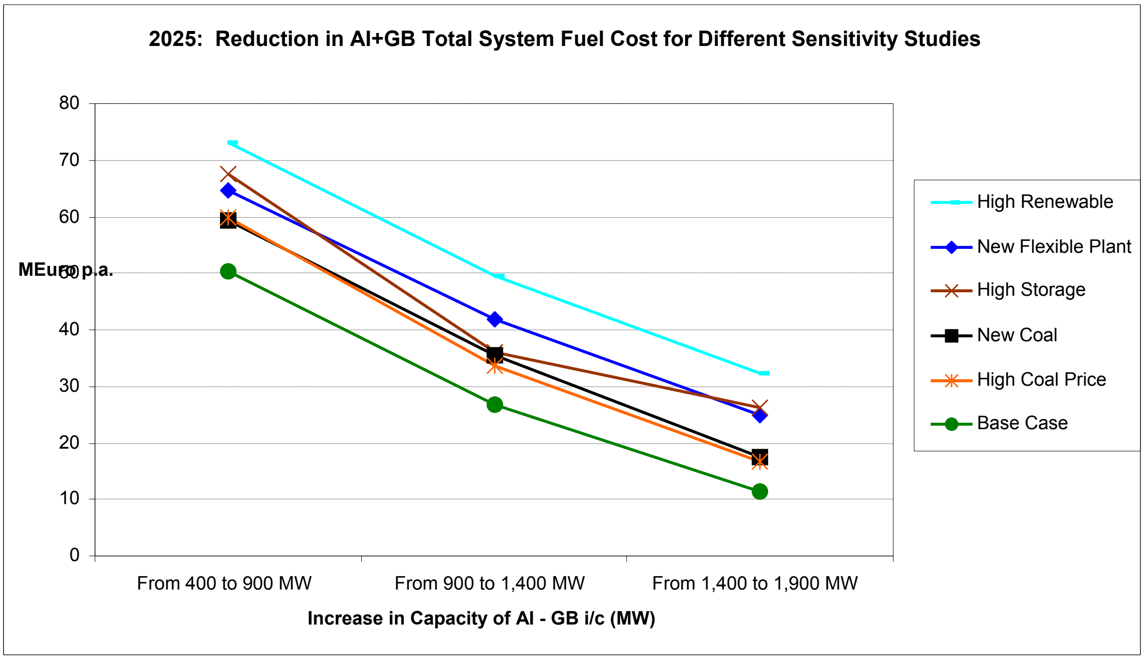

Figure 5.66 Reduction in total system production cost, for the AI and GB systems in 2025.

In all cases, there is a diminishing benefit from increasing AI-GB interconnection capacity by 500 MW. The lowest benefit is observed with the Base Case assumptions.

5.4.2 Wind Curtailment in AI

Wind curtailment in AI is reduced by interconnection with GB. There is negligible wind curtailment on the GB system. The following graph (Figure 5.67) shows the effect for the AI system.

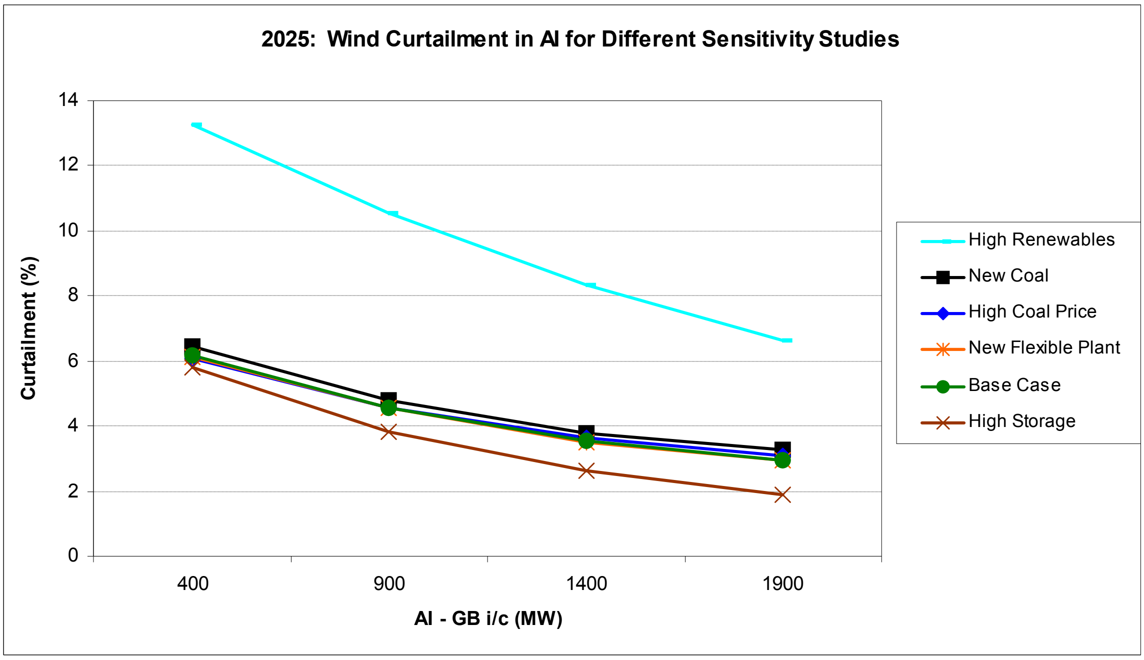

Figure 5.67 Effect of Interconnection on Wind Curtailment in 2025.

In the High Wind study, wind curtailment is greatest, as is the benefit from increasing interconnection. The case which shows lowest curtailment is the large pumped storage unit.

5.4.3 Flows from AI to GB

The following graph (Figures 5.68) shows the net interconnector flows for the different interconnection capacity assumptions. The predominant flow is from AI to GB. The exceptions are the scenarios with high wind and new coal units in AI.

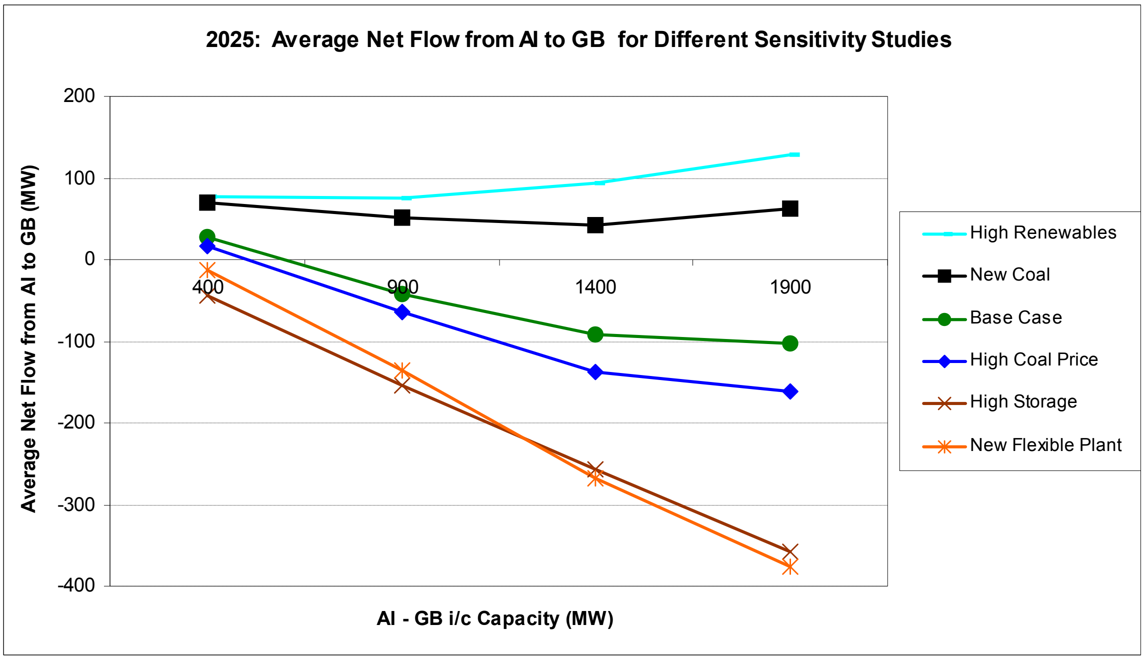

Figure 5.68 Effect of Interconnection Capacity on Average Net Flow from AI to GB.

The capacity factor of the interconnector can be determined from the absolute value of the flows. The following graph (Figure 5.69) shows the capacity factors for the different studies and interconnection capacity assumptions. Increasing the capacity reduces the capacity factor.

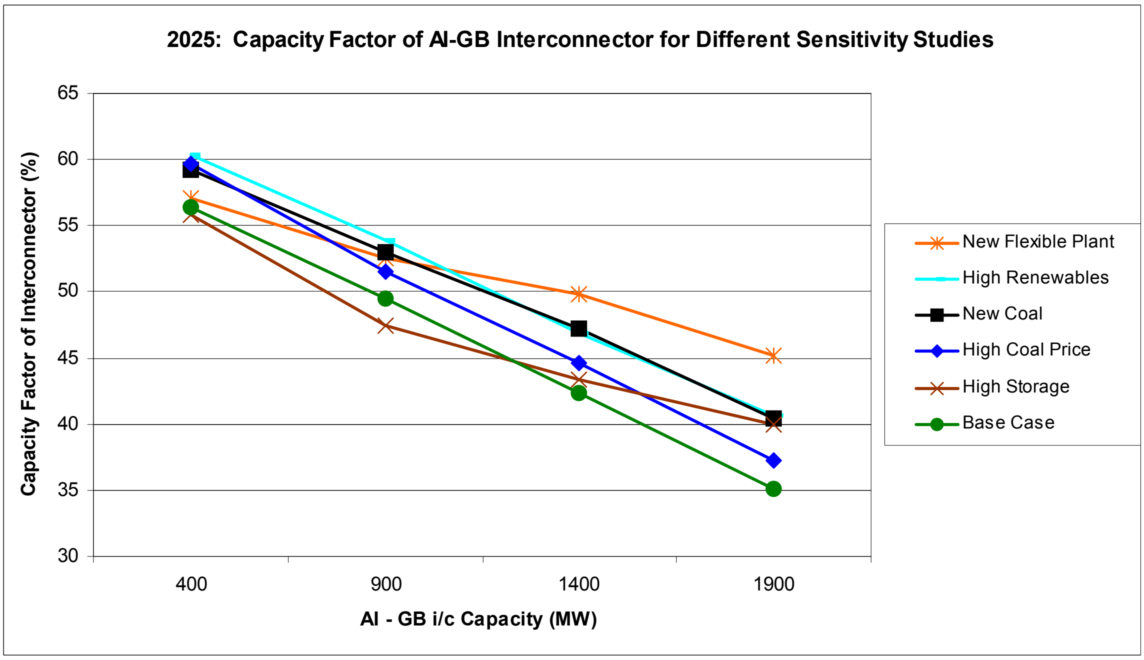

Figure 5.69 Effect of Interconnection Capacity on Capacity Factor of Interconnector.

5.4.4 CO2 Emissions in AI

CO2 Emissions in AI are reduced by interconnection with GB – see Figure 5.70.

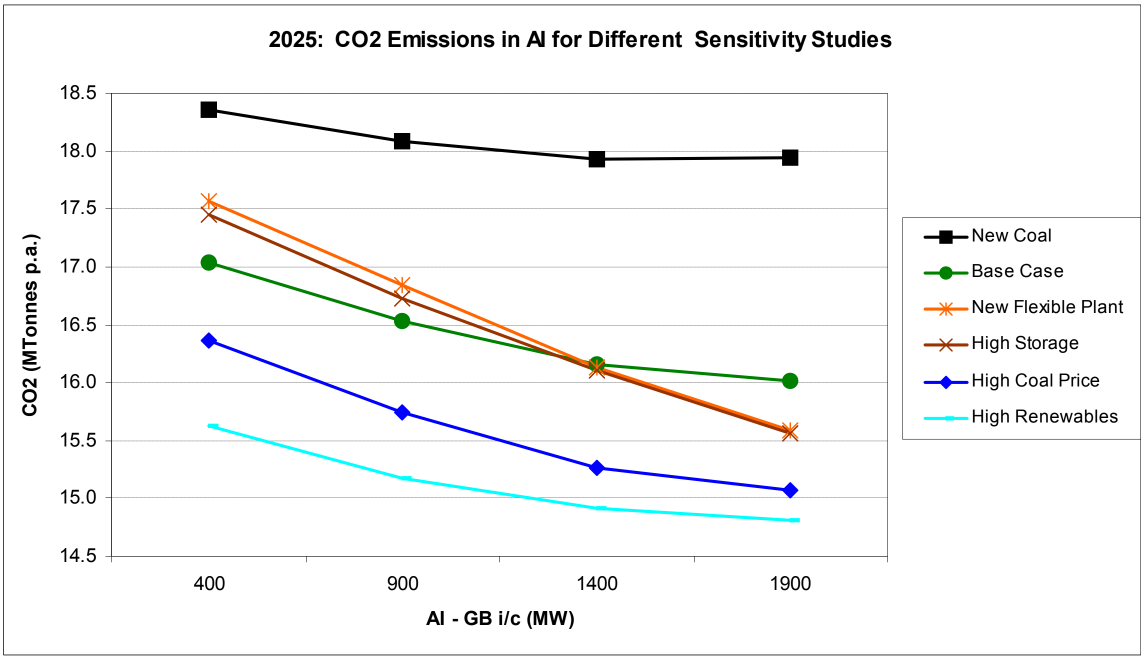

Figure 5.70 Effect of Interconnection Capacity on CO2 Emissions in AI.

5.4.5 System Marginal Price (SMP)

The following graphs (Figures 5.71 and 5.72) show the effect of interconnection on average Marginal Price in AI and GB. The trend is downwards for the AI system: Interconnection with GB tends to reduce the average Marginal Price. There is a slight upward trend for the GB system.

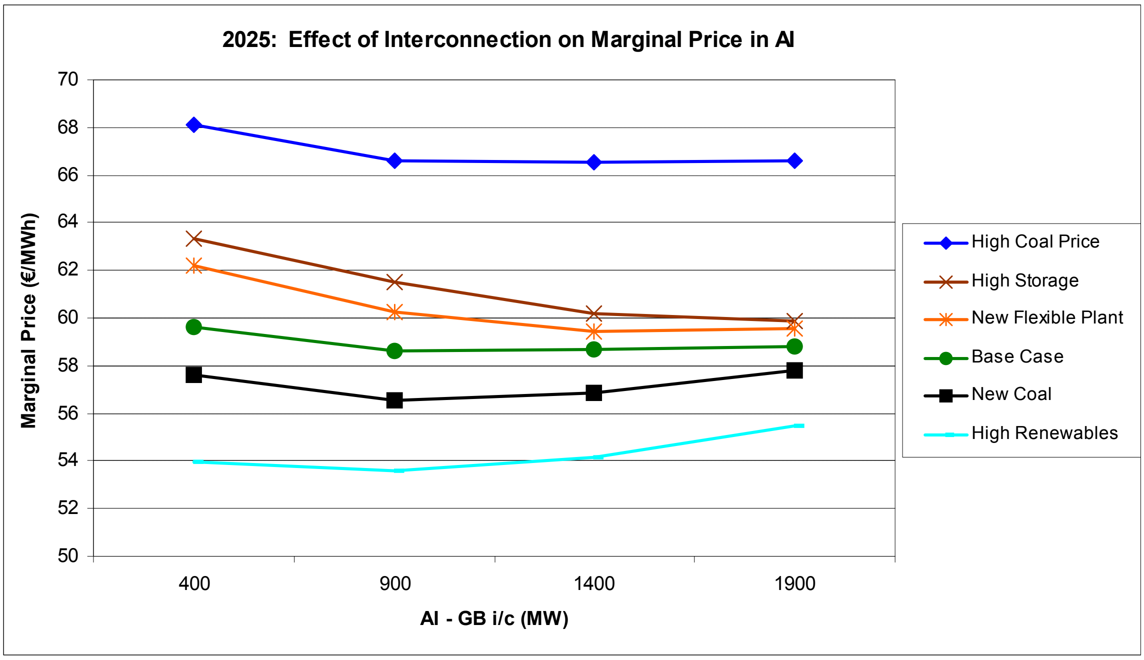

Figure 5.71 Effect of Interconnection on AI Marginal Price in 2025.

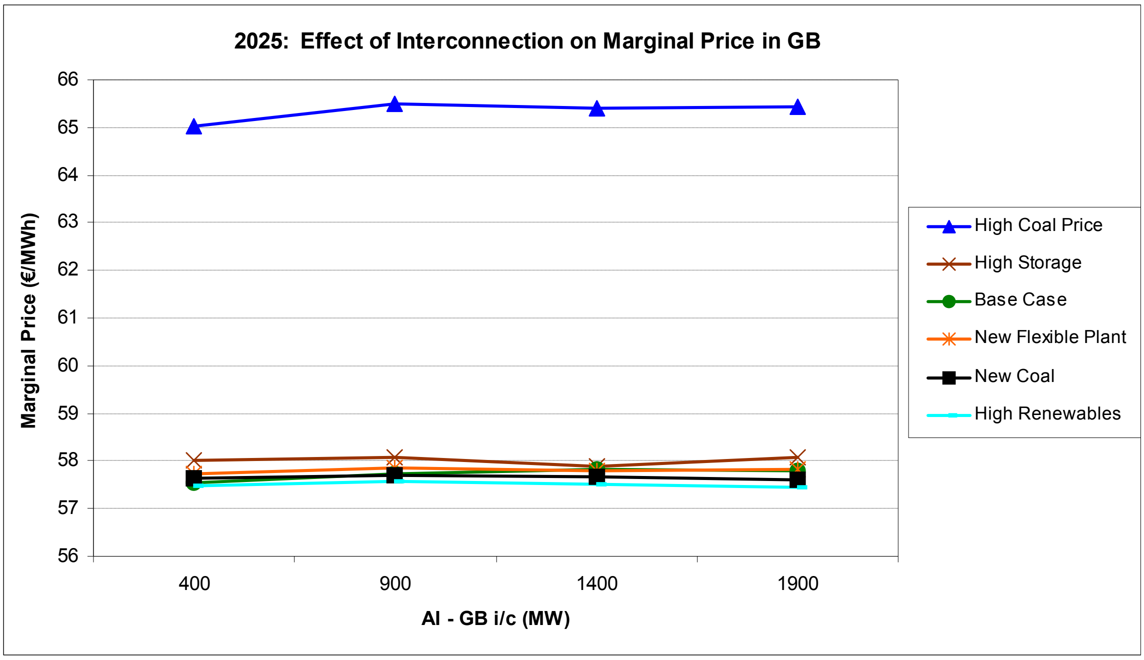

Figure 5.72 Effect of Interconnection on GB Marginal Price in 2025.

As the smaller system, the average annual SMP in AI is more volatile than in GB. The SMPs in GB are affected very little by the interconnector size, with one exception: the High Coal Price scenario, which affects the price of thermal units within GB.

5.4.6 Congestion Rent

Figure 5.73 below gives the congestion rents for the AI-GB interconnector. Figure 5.74 shows the congestion rents expressed as Euro per kW-year.

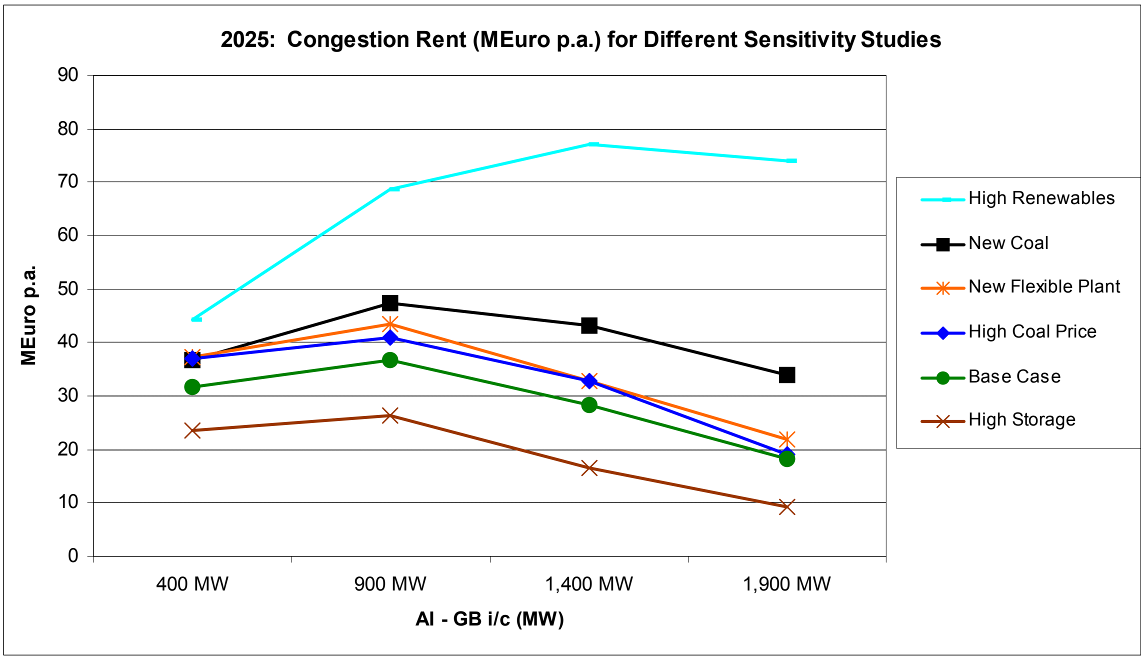

Figure 5.73: Congestion Rent (MEuro p.a.) in 2025.

The congestion rents (expressed as MEuro p.a.) tend to decrease when the interconnector capacity increases beyond a certain level. In all six cases, the congestion rents decrease between 1400 and 1900 MW. In five cases, the congestion rents decrease between 900 and 1400 MW. When expressed as Euro / (kW x year), the values decrease for all increases in capacity:

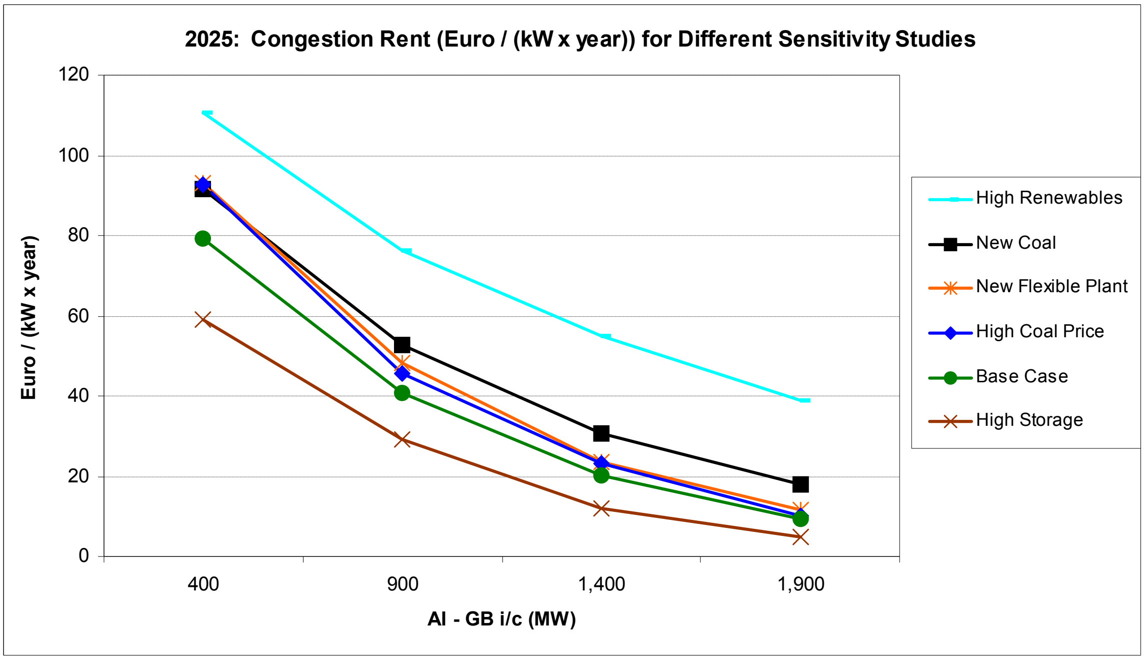

Figure 5.74 Congestion Rent (Euro / (kW x year)) in 2025.

5.5 Capacity Benefit of AI-GB Interconnector

Generation adequacy studies were carried out to estimate the capacity benefit of the AI-GB interconnector. One year (2020) was examined. The interconnector capacity was increased, and corresponding amounts of Open Cycle Gas Turbine (OCGT) on the AI and GB systems was omitted to achieve the original system adequacy values (in loss-of-load expectation (LOLE) terms). The results are given in Figure 5.75:

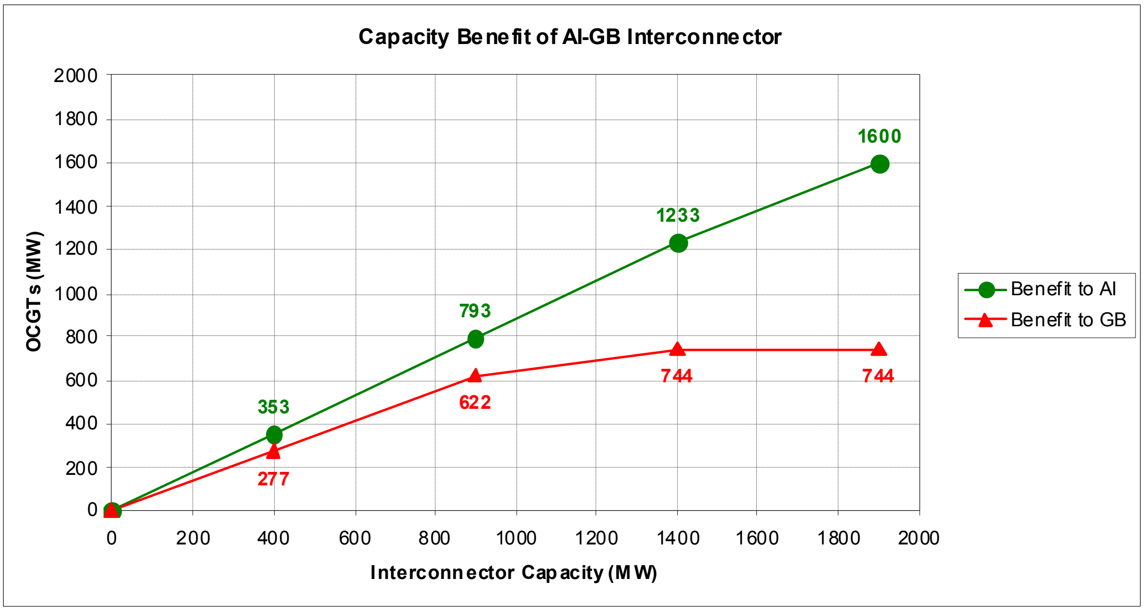

Figure 5.75 Capacity Benefit of AI-GB Interconnector.

The results show that the benefit to AI is much higher than for GB. This is because AI sometimes does not have the spare generation to provide maximum export on the interconnector. In contrast, the much larger GB system usually has spare generation to provide maximum export to AI.

What is the value of this capacity? In the All-Island Single Electricity Market (SEM) there is a Capacity Payment Mechanism (CPM) which values generation capacity at the cost of connecting a least-cost, technically acceptable generator known as the Best New Entrant. This is typically a medium size OCGT. This is valued at 80.11 €/(kW x year) for 2010. On this basis, the following capacity benefits would apply:

Increase in Capacity of AI-GB Interconnector	Equivalent OCGT saving (€M p.a.)		
	AI	GB	AI + GB
From 400MW to 900MW	35	28	63
From 900MW to 1,400MW	35	10	45
From 1,400MW to 1,900MW	29	0	29

Table 5.16: Capacity savings from AI-GB interconnector.

To realise the full capacity benefits for four interconnectors to GB would mean AI placing 1600MW capacity dependence on these interconnectors. We may not want to put this much reliance on electricity imports as a matter of policy. A more conservative approach would be to place a lower reliance on interconnector capacity, e.g. 75% or 50%.

5.6 Combined Capacity Benefits and Production Cost Savings

5.6.1 Overall Benefits of AI-GB Interconnection

Two categories of benefit were quantified: reduction in production costs and capacity benefits. While there are other potential benefits such as provision of services and greater competition, we do not consider them here.

Production costs in this report comprise fuel costs and CO_2 costs. Production cost savings arise because the more efficient generators can be used to meet demand on both interconnected grids up to the capacity of the interconnection. There are substantial production cost savings for some of the scenarios studied. For example, in 2020, an additional 500MW interconnector between the island of Ireland and Great Britain would bring production cost savings in the range €25 - €50 million.

Regarding capacity benefits, interconnection was estimated to displace about 88% of best-new-entrant OCGT plant in the AI system, although this ratio decreased slightly beyond 1400MW of interconnection. Applying the same methodology to the Great Britain system, the benefit was approximately 69% of OGCT plant up to 900MW of interconnection, saturating thereafter until no benefit is obtained.

Overall benefits were calculated by combining reduction in production costs and capacity benefits. This was carried out for various scenarios, number of interconnectors, and years.

As outlined in section 1.3.13 a 500MW interconnector between Ireland and Great Britain would cost in the range of **€36 - €43m annualised.**

Figure 5.76 shows combined production cost savings and capacity benefit (both 100%) for AI-GB interconnection. The benefits exceed the costs for all scenarios up to 1400MW, and some scenarios up to 1900MW.

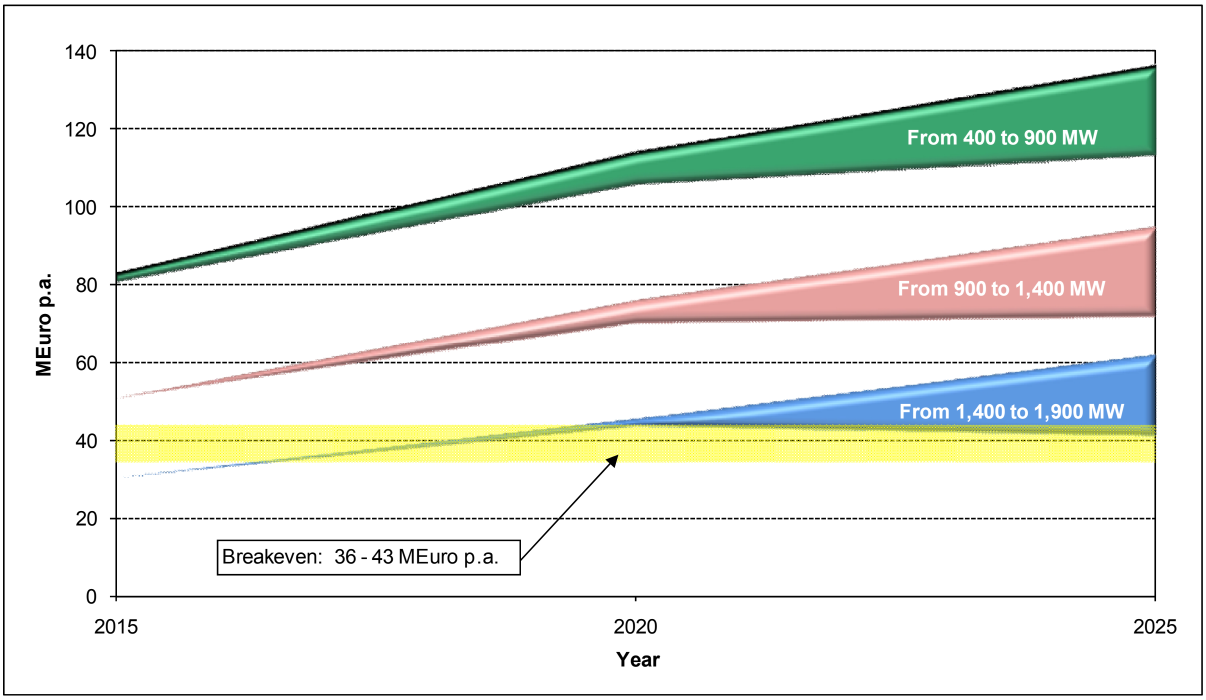

Figure 5.76 Combined production cost savings (100%) and capacity benefit (100%) for AI - GB interconnection.

Based on Figure 5.76, it can be seen that, in general, benefits increase over time from 2015 out to 2025.

There is limited benefit from an additional interconnector, aside from the East-West interconnector, up to 2015.

There is an economic case for a third interconnector to Great Britain by 2020.

A fourth interconnector to Great Britain is economically justified post-2020 for some scenarios such as High Renewables.

5.6.2 Range of Benefits of AI-GB Interconnection

We may not want to put 100% reliance on the full capacity benefits as a matter of policy. A more conservative approach would be to place a lower reliance. In addition, factors such as market inefficiency could prevent full production cost savings from being realized. Table 5.17 examines the net benefits of interconnection based on the following combinations:

- 100% or 80% of the savings in production costs are realised.
- 100%, 75% or 50% of the maximum capacity benefits to AI and GB are assumed.

Change in Interconnector Capacity	Production Cost Savings	Capacity Benefits	Net Benefits (€M p.a.)		
	% of AI-GB total	% of AI-GB total	2015	2020	2025
From 400 to 900 MW	100%	100%	42.4	70.4	85.1
		75%	26.7	54.7	69.4
		50%	10.9	38.9	53.7
	80%	100%	38.6	61.0	72.8
		75%	22.9	45.3	57.1
		50%	7.1	29.5	41.3
From 900 to 1,400 MW	100%	100%	11.5	33.5	43.7
		75%	0.3	22.3	32.5
		50%	-11.0	11.0	21.2
	80%	100%	10.3	27.9	36.1
		75%	-0.9	16.7	24.8
		50%	-12.2	5.4	13.6
From 1,400 to 1,900 MW	100%	100%	-9.1	4.9	11.8
		75%	-16.5	-2.5	4.5
		50%	-23.8	-9.8	-2.9
	80%	100%	-9.3	1.9	7.4
		75%	-16.7	-5.5	0.1
		50%	-24.0	-12.8	-7.3

Table 5.17 Net Benefits (€M p.a.) of AI-GB Interconnection to the AI-GB System

Cells with a white background indicate a positive net benefit, cells with a grey background show results within the breakeven zone, while cells with a pink background indicate a negative net benefit.

The East-West Interconnector (i.e. increasing interconnection from 400MW to 900MW) shows a positive net benefit in all combinations.

There is an economic case for a third interconnector (from 900MW to 1400MW) by 2020.

A fourth interconnector to Great Britain is not economically justified up to 2020, however some scenarios show a net benefit in 2025.

5.6.3 Ireland-France Interconnection

These studies indicated high capacity factor for the Ireland-France interconnectors, and reduction in production costs as shown in Table 5.18.

Savings (€M p.a.)	2015	2020	2025
AI - FR i/c from 0MW to 500MW	38	56	63
AI - FR i/c: from 500MW to 1,000MW	27	37	37

Table 5.18 Production cost savings for 500MW and 1000MW interconnection between the island of Ireland and France

Regarding capacity benefits, a reasonable assumption is to use the same results obtained when examining the AI-GB system (see Table 5.16). On this basis, a 500MW interconnector (up to 1,000MW of interconnection) would have a capacity value of €35m p.a. to the AI system, and €28m p.a. to the French system, giving a total value of €63m p.a.

In Section 4.13.2, the cost of an Ireland-France 500MW interconnector was estimated to be in the range €55 - €66m p.a.

Examining the system simulation results at a more detailed level showed factors which are difficult to explain. The problems could be due to the French system being modelled in a less thorough manner than the All-Island system. Without a detailed generation model for France, it is not possible to validate the results. Accordingly, these results need to be corroborated by more detailed modelling. This we intend to carry out and, if there is a significant change in the results, then we will publish an addendum to this report.

6 CONCLUSIONS

The analysis reinforces the very strong economic case for the planned East-West Interconnector for all years studied (2015, 2020 and 2025). A further (third) 500MW interconnector between AI and GB is economically attractive in 2020, and more so in 2025. A fourth 500MW interconnector between AI and GB is not economically feasible until 2025; even then, only some scenarios are feasible, such as High Renewables.

A 500MW and 2 x 500MW interconnection between AI and France was modelled in 2015, 2020, and 2025. These studies indicated high capacity factor for the Ireland-France interconnector, and corresponding reductions in production cost. However, these results need to be corroborated by more detailed modelling before any recommendations could be made on Ireland-France interconnection.

In general, interconnection becomes more economically attractive further out in time. A High Renewables scenario improves the case for interconnection. The incremental benefits of interconnection decrease with each subsequent interconnector.

The production cost savings that are evaluated in this report are the total benefits to both sides; savings are not apportioned between the parties. EirGrid recommends that there is engagement with responsible agencies on the island of Ireland and abroad to create a framework for funding of new interconnectors.

The following next steps follow on from this report:

- Produce a work programme to develop detailed costings and investigate technical feasibility of different interconnector options and routes, that can be used as an input to investment decisions. In parallel with this, it is necessary to develop arrangements for funding of interconnectors.

- Investigate increasing the export capability of Moyle Interconnector. In terms of capability, the Moyle Interconnector can import 450MW from Scotland in winter and 400MW in summer. However, the Moyle Interconnector is limited by contractual arrangements to an export capacity to Scotland of 80MW. There is economic benefit from increasing the export capability from 80MW to 400MW. This removal of this restriction is currently under review by Moyle Interconnector Ltd, the owner of the Moyle Interconnector.

- Carry out further studies on the economic benefit of Ireland–France interconnection. There is uncertainty about the validity of the modelling results for Ireland–France interconnection. More detailed modelling of the French power system is needed to vouch for the results obtained. We will have to take into account the fact that France is highly interconnected already. EirGrid intends to do this more detailed modelling of France and its connected systems. If there is a significant change in the results, then we will publish an addendum to this report.

- Market issues are significant. The benefits identified in this report can only accrue if there is efficient market coupling between the island of Ireland, Great Britain and France. EirGrid welcomes the recent consultation paper issued by the Regulatory Authorities 'SEM Regional Integration'. This is directly addressed at how to best leverage the interconnectors to reduce costs and lower prices. EirGrid, as system operator and market operator, are committed to working pro-actively with the Regulatory Authorities and all stakeholders to deliver efficient market arrangements that meet the needs of stakeholders and comply with EU directives.

- Investigate offshore grids. In the next 20 years there are likely to be substantial off-shore wind farms developed in the Irish Sea: both on the Irish coast and the English-Wales-Scotland coasts. EirGrid is publishing an Offshore Grid Strategy to set out a roadmap for the development of off-shore grids. The aim of the strategy is not just to connect off-shore wind farms but also to coordinate these connections with transmission grid developments and interconnector developments. The need to connect the off-shore wind farms presents an opportunity to coordinate with interconnector developments and realise more efficient outcomes.

Appendix 1 INTERCONNECTOR CHARACTERISTICS

HVDC Interconnector Technology

HVDC stands for High Voltage Direct Current.

HVDC is generally chosen instead of AC for underwater projects due to the length of submarine cable required (80 km is the approximate breakeven distance). AC cable is infeasible for long transmission distances, because the capacitive charging current can use up a large part of the cable current carrying capacity such that less power can be transmitted. Conversely, with HVDC there is no reactive power flow and power can be transmitted over much longer distances.

HVDC has other advantages over AC:

- The two networks can be operated independently
- Faults don't transfer across interconnected systems
- Precise and rapid control of delivered power

HVDC Light is ABB's Trademark for High Voltage Direct Current transmission system based on solid state Voltage Source Converter (VSC) technology. An alternative technology is Line Commutated Converter (LCC).

Features of LCC:

- Based on thyristors (carry current in one direction only)
- DC voltage changes polarity when power direction changes
- LCC HVDC is available up to ±800kVdc, 6400/9000MW
- AC voltage must be reasonably firm (SCR > 2.5) for correct LCC operation
- AC/DC/AC Conversion efficiency is high (about 98.5% excluding line or cable loss)
- Likely to be the main solution for >500MW.

Features of VSC:

- Based on Insulated-Gate Bipolar Transistors (IGBTs)
- The first VSC schemes at up to ±150kVdc had the valves in individual enclosures, which facilitate rapid installation.
- Gives additional degrees of freedom, e.g. independence of converters
- Reduces lower order harmonics – smaller filters
- Higher speed of response.
- Power loss larger because of more frequent switching.
- Extruded polymeric cables can be used, as the dc voltage does not change polarity; they are lighter, with no significant environmental risks.

Source: Andersen Power Electronic Solutions Ltd

Appendix 2 NON-QUANTIFIABLE I/C BENEFITS

Chapter 5 (Results) focused on the quantifiable benefits of interconnection. There are significant benefits from additional interconnection that are difficult to cost precisely. These are described below:

Improved fuel diversity

The introduction of interconnection will diversify the fuel sources used to generate electricity available on the Irish system.

Greater competition

Interconnection will promote further competition in the electricity market as it will allow third party access in a fair, consistent and transparent manner; this in turn should assert downward pressure on electricity prices.

Closer European integration

Additional interconnection projects may receive financial support from the EU. The importance of the East West Interconnector (EWIC) project currently under construction has been recognised at a European level. EWIC has been designated a "Project of European interest" and is included in the EU Trans-European Networks Priority Interconnection Plan and is currently receiving some finance to cover aspects of project development. In addition, Great Britain is also developing interconnectors with mainland Europe to further contribute to security of supply and market integration. Interconnection between AI and GB would also indirectly open the Irish market to the wider European market.

Renewable integration

The benefits of reduced wind curtailment are captured in the reduced production costs of the combined AI-GB system. In addition, there are potential benefits of avoiding penalties from failure to meet emissions targets.

Appendix 3 ALL-ISLAND PORTFOLIOS

2015 All-Island Portfolio

Generator	Fuel Type	Export Capacity (MW)
Biomass	Biomass	77
CHP	CHP	155
Moneypoint Unit 1	Coal	281.5
Moneypoint Unit 2	Coal	281.5
Moneypoint Unit 3	Coal	281.5
Rhode Unit 1	Distillate Oil	52
Rhode Unit 2	Distillate Oil	52
Tawnaghmore Unit 1	Distillate Oil	52
Tawnaghmore Unit 2	Distillate Oil	52
Aghada CCGT	Gas	420
Aghada Unit 1	Gas	258
Aghada Unit 11	Gas	90
Aghada Unit 12	Gas	90
Aghada Unit 13	Gas	90
Ballylumford CCGT	Gas	490
Ballylumford GT1	Gas	58
Ballylumford GT2	Gas	58
Ballylumford Unit 10	Gas	97
Ballylumford Unit 4	Gas	170
Coolkeeragh CCGT	Gas	402
Coolkeeragh GT8	Gas	53
Dublin Bay Power	Gas	403
Great Island CCGT	Gas	403
Huntstown Unit 1	Gas	340
Huntstown Unit 2	Gas	398
Kilroot GT1	Gas	29
Kilroot GT2	Gas	29
Kilroot GT3	Gas	40
Kilroot GT4	Gas	40
Kilroot Unit 1	Coal	238
Kilroot Unit 2	Coal	238
Marina	Gas	85
New OCGT1	Gas	98
New OCGT2	Gas	98
New OCGT3	Gas	98
North Wall Unit 4	Gas	109
North Wall Unit 5	Gas	109
Poolbeg CCGT	Gas	460
Sealrock Unit 3	Gas	80.5
Sealrock Unit 4	Gas	80.5
Tynagh	Gas	384
Whitegate	Gas	445
Ardnacrusha	Hydro	86
Erne	Hydro	65

Lee	Hydro	27
Liffey	Hydro	38
Other Hydro	Hydro	24.2
Industrial	Industrial	9
Edenderry	Peat	117.6
Lough Ree	Peat	91
West Offaly Power	Peat	137
Turlough Hill	Pumped Storage	292
RoI Wind	Wind	2891
NI Wind	Wind	968
Total Generation:		12,511.3

2020 All-Island Portfolios

Generator	Fuel Type	Base Case Scenario Export Capacity (MW)	New OCGTs Scenario Export Capacity (MW)
Biomass	Biomass	109	109
CHP	CHP	180	180
Moneypoint Unit 1	Coal	281.5	281.5
Moneypoint Unit 2	Coal	281.5	281.5
Moneypoint Unit 3	Coal	281.5	281.5
Rhode Unit 1	Distillate Oil	52	52
Rhode Unit 2	Distillate Oil	52	52
Tawnaghmore Unit 1	Distillate Oil	52	52
Tawnaghmore Unit 2	Distillate Oil	52	52
Aghada CCGT	Gas	420	420
Aghada Unit 1	Gas	258	258
Ballylumford CCGT	Gas	490	490
Ballylumford GT1	Gas	58	58
Ballylumford GT2	Gas	58	58
Ballylumford Unit 10	Gas	97	97
Ballylumford Unit 4	Gas	170	170
Coolkeeragh CCGT	Gas	402	402
Coolkeeragh GT8	Gas	53	53
Dublin Bay Power	Gas	403	403
Great Island CCGT	Gas	403	403
Huntstown Unit 1	Gas	340	340
Huntstown Unit 2	Gas	398	398
Kilroot GT1	Gas	29	29
Kilroot GT2	Gas	29	29
Kilroot GT3	Gas	40	40
Kilroot GT4	Gas	40	40
Kilroot Unit 1	Coal	238	238
Kilroot Unit 2	Coal	238	238
Marina	Gas	85	85
New CCGT1	Gas	400	
New OCGT1	Gas	98	98
New OCGT2	Gas	98	98
New OCGT3	Gas	98	98
New OCGT4	Gas		98
New OCGT5	Gas		98
New OCGT6	Gas		98
New OCGT7	Gas		98
Poolbeg CCGT	Gas	460	460
Sealrock Unit 3	Gas	80.5	80.5
Sealrock Unit 4	Gas	80.5	80.5
Tynagh	Gas	384	384
Whitegate	Gas	445	445
Ardnacrusha	Hydro	86	86
Erne	Hydro	65	65
Lee	Hydro	27	27
Liffey	Hydro	38	38
Other Hydro	Hydro	24.2	24.2
Industrial	Industrial	9	9

Edenderry	Peat	117.6	117.6
Lough Ree	Peat	91	91
West Offaly Power	Peat	137	137
Turlough Hill	Pumped Storage	292	292
Wave	Wave	120	120
RoI Wind	Wind	5389	5389
NI Wind	Wind	1248	1248
Total Generation:		16,378.3	16,370.3

2025 All-Island Portfolios

Generator	Fuel Type	Base Case Scenario Export Capacity (MW)	New OCGTs Scenario Export Capacity (MW)	New Clean Coal Scenario Export Capacity (MW)	High Wind Scenario Export Capacity (MW)	New Pumped Storage Scenario Export Capacity (MW)
Biomass	Biomass	140	140	140	140	140
CHP	CHP	205	205	205	205	205
Moneypoint Unit 1	Coal	281.5	281.5		281.5	281.5
Moneypoint Unit 2	Coal	281.5	281.5		281.5	281.5
Moneypoint Unit 3	Coal	281.5	281.5		281.5	281.5
New Coal 1	Coal			387.5		
New Coal 2	Coal			387.5		
New Coal 3	Coal			387.5		
New Coal 4	Coal			387.5		
Rhode Unit 1	Distillate Oil	52	52	52	52	52
Rhode Unit 2	Distillate Oil	52	52	52	52	52
Tawnaghmore Unit 1	Distillate Oil	52	52	52	52	52
Tawnaghmore Unit 2	Distillate Oil	52	52	52	52	52
Aghada CCGT	Gas	420	420	420	420	420
Ballylumford GT1	Gas	58	58	58	58	58
Ballylumford GT2	Gas	58	58	58	58	58
Ballylumford Unit 10	Gas	97	97	97	97	97
Ballylumford Unit 4	Gas	170	170	170	170	170
Ballylumford CCGT	Gas	490	490	490	490	490
New CCGT1	Gas	400			400	
New CCGT2	Gas	400			400	
New CCGT3	Gas	400			400	
Coolkeeragh GT8	Gas	53	53	53	53	53
Coolkeeragh CCGT	Gas	402	402	402	402	402
Dublin Bay Power	Gas	403	403	403	403	403
Great Island CCGT	Gas	403	403	403	403	403
Huntstown Unit 2	Gas	398	398	398	398	398
Huntstown Unit 1	Gas	340	340	340	340	340
Kilroot Unit 1	Coal	238	238	238	238	238
Kilroot Unit 2	Coal	238	238	238	238	238
Kilroot GT1	Gas	29	29	29	29	29
Kilroot GT2	Gas	29	29	29	29	29
Kilroot GT3	Gas	40	40	40	40	40
Kilroot GT4	Gas	40	40	40	40	40
New OCGT1	Gas	98	98	98	98	98
New OCGT2	Gas	98	98	98	98	98
New OCGT3	Gas	98	98	98	98	98
New OCGT4	Gas	98	98	98	98	98
New OCGT5	Gas	98	98	98	98	98
New OCGT6	Gas	98	98	98	98	98
New OCGT7	Gas	98	98	98	98	98

New OCGT8	Gas	98	98	98	98	98
New OCGT9	Gas		98	98		98
New OCGT10	Gas		98	98		98
New OCGT11	Gas		98	98		
New OCGT12	Gas		98	98		
New OCGT13	Gas		98	98		
New OCGT14	Gas		98			
New OCGT15	Gas		98			
New OCGT16	Gas		98			
New OCGT17	Gas		98			
New OCGT18	Gas		98			
New OCGT19	Gas		98			
New OCGT20	Gas		98			
Poolbeg CCGT	Gas	460	460	460	460	460
Sealrock Unit 3	Gas	80.5	80.5	80.5	80.5	80.5
Sealrock Unit 4	Gas	80.5	80.5	80.5	80.5	80.5
Tynagh	Gas	384	384	384	384	384
Whitegate	Gas	445	445	445	445	445
Ardnacrusha	Hydro	86	86	86	86	86
Erne	Hydro	65	65	65	65	65
Lee	Hydro	27	27	27	27	27
Liffey	Hydro	38	38	38	38	38
Other Hydro	Hydro	24.2	24.2	24.2	24.2	24.2
Industrial	Industrial	9	9	9	9	9
Edenderry	Peat	117.6	117.6	117.6	117.6	117.6
Lough Ree	Peat	91	91	91	91	91
West Offaly Power	Peat	137	137	137	137	137
New Pumped Storage	Pumped Storage					1508
Turlough Hill	Pumped Storage	292	292	292	292	292
Wave	Wave	500	500	500	500	500
RoI Wind	Wind	5845	5845	5845	8000	5845
NI Wind	Wind	1528	1528	1528	1528	1528
Total Generation:		18,497.3	18,473.3	18,492.8	20,652.3	19,001.3

EirGrid Plc

The Oval, 160 Shelbourne Road, Ballsbridge, Dublin 4
TELEPHONE: +353 (0)1 677 1700   FAX: +353 (0)1 661 5375   EMAIL: info@eirgrid.com
www.eirgrid.com