SINCLAIR KNIGHT MERZ
SKM

OFFSHORE GRID DEVELOPMENT FOR A SECURE RENEWABLE FUTURE – a UK Perspective | June 2010

Sinclair Knight Merz
13th Floor, Cale Cross House
156 Pilgrim Street
Newcastle upon Tyne
NE1 6SU
United Kingdom
Tel: +44 191 211 2400
Fax: +44 191 211 2401
www.skmconsulting.com

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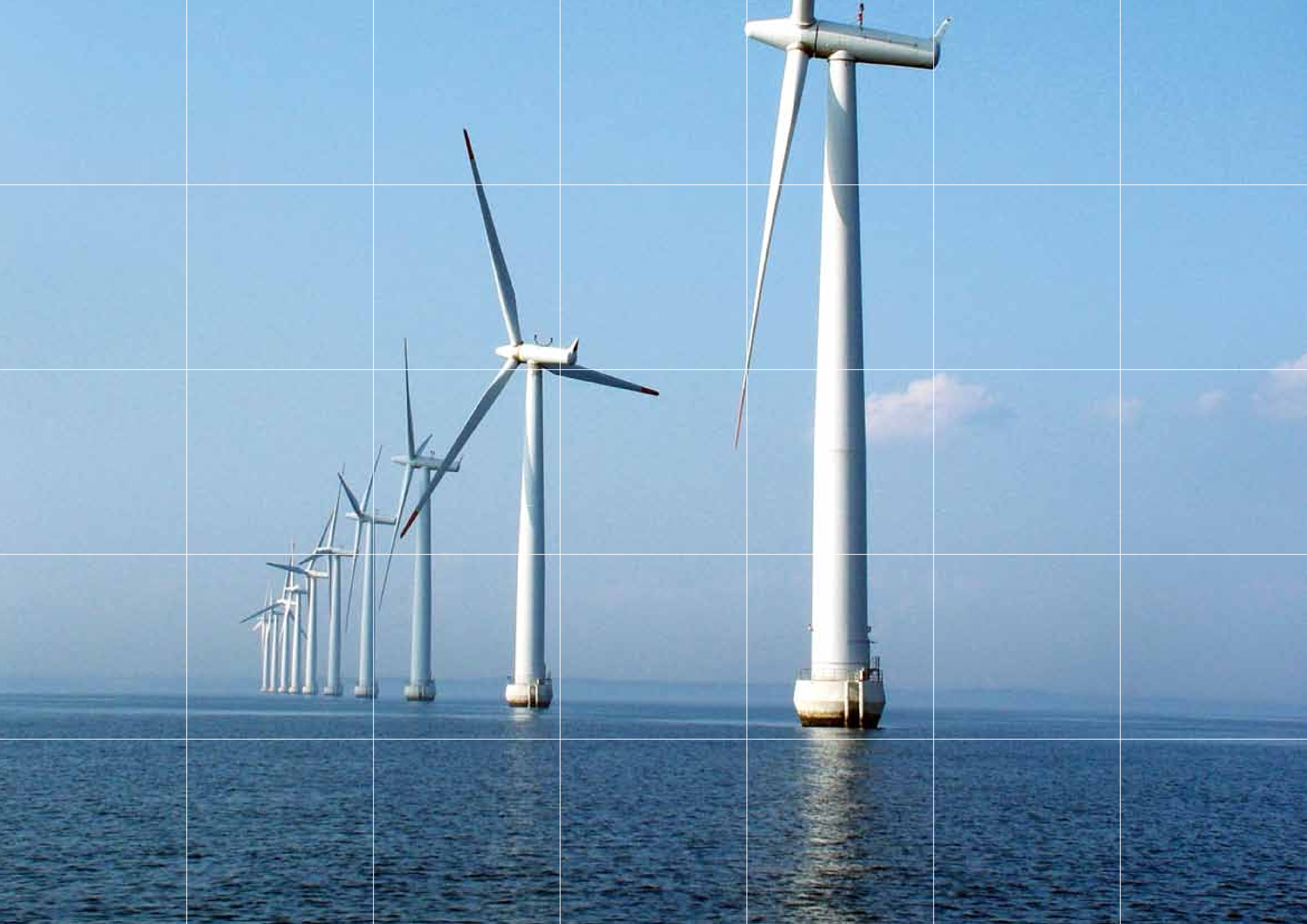

Executive Summary

Sinclair Knight Merz (SKM), in association with Deloitte, was appointed by the Department for Energy and Climate Change (DECC) to undertake a high level review of the costs and benefits, from a UK perspective, of developing renewable Joint Projects (JP) with third countries with direct interconnection to the UK, together with scope for the combined development of offshore grids.

In order to explore the potential of JP development and resulting interconnection, a high level cost benefit analysis (CBA) of the technical and economic drivers and constraints underpinning such developments has been undertaken. The CBA considers a range of potential JP developments between the UK and third parties. The aim is to help answer, from a UK perspective, two questions:

- Can offshore wind offer a vehicle for cost effective interconnection?
- Does JP development offer a cost effective route to help the UK meet its renewable and carbon targets and achieve greater interconnection?

In addition to renewable generation, there are potential other benefits of providing interconnection between the UK and any of the areas considered in our study. The cost benefit analysis we have undertaken has identified a range of potential benefits for the UK from entering JP with interconnection, including:

- Additional renewable generation
- Potential carbon savings
- Balancing cost reductions
- Security of supply implications
- Wholesale price impacts

Four potential areas around the UK were examined for such potential JP development namely Norway (North Sea), Ireland (Irish Sea), Continental Europe (English Channel area) and Iceland.

In the assessment of JPs involving the integration of offshore wind farms into offshore grids it is important to take into account not only the economic considerations but also the technical constraints involved. Technical constraints include the capacity limitations of DC transmission technology and the operational security of supply considerations for interconnected grids.

The most cost effective method of connecting wind farms far from shore is using VSC (Voltage Source Converter) DC technology. Currently VSC DC technology is limited to around 1 GW per link. As a result there could be reduced attractiveness in integrating wind farms with interconnections. In many cases the benefits of interconnection are likely to be achieved more efficiently via conventional direct onshore point to point interconnections using conventional CSC (Current Source Converter) DC transmission technology which allows much higher voltages and transfer capacities. The experience record of CSC DC is also significantly larger.

Although it is expected that developments in VSC DC technology will increase its efficiency, operating voltages and transfer capacities over time it is likely that, for 2020, the majority of developments will largely involve currently available technology. Other related developments such as DC circuit breakers may make the interconnection of wind farms more attractive.

However, whether using AC or DC technology offshore, the operational safety of the grid will ultimately limit the capacity of the onshore offshore links to cover for generation shortfalls caused by faults in the links. This constraint corresponds to the maximum planned infeed loss risk of the grid and is currently about 1.3 GW in GB and 3 GW in continental Europe. Beyond those transfer levels, the provision of additional network redundancy and/or reserve will be required. These limitations also question the feasibility and attractiveness of “hubbing” or aggregating large offshore wind farms.

Norway

A key driver underpinning the study is the potential contribution that JP development may make towards helping the UK, cost effectively, meet its 2020 renewable targets (and contribute to carbon targets). For Norway a key question to resolve is whether the existing hydro generation that dominates the Norwegian electricity sector would count towards renewable targets in other EU member states under the 2009 Renewable Energy Directive.

As a general rule, the EU Renewable Energy Directive allows imported renewable generation from non-EU countries to count towards a Member State's target only if the electricity is produced by a new installation, or by the increased capacity of an installation refurbished after the Directive came into force (June 2009). Norway is anticipating the development of an additional 11 TWh of hydro by 2025 and 11 TWh of wind, both of which may be open for JP development with the UK. However, the cost effectiveness of onshore JP development in Norway will depend on the economics of capital intensive hydro generation.

A number of interconnection options were considered, including interconnection via Dogger Bank, via the Shetland Islands, a three way UK-Norway-Benelux option with Dogger Bank as a 'hub' and also a direct onshore to onshore interconnection between the UK and Norway.

Two cases were analysed in detail to examine the potential benefits of interconnection; a 1000 MW direct interconnection with Norway and the interconnection via Dogger Bank – a 500 MW link from Norway to a 500 MW wind farm at Dogger Bank linked by a 1000 MW

Interconnection Cost	Offshore wind 500 MW	Direct Link GB-Norway 500 MW	Direct Link GB-Norway '1000 MW	GB-Norway (500 MW) via Wind Farm Dogger-GB 1000 MW	GB-Norway (500 MW) via Wind Farm Dogger-GB 500 MW
Cable costs £m	50	347	451	505	413
Converters £m	170	120	180	254	227
Total £m	**220**	**467**	**631**	**759**	**640**
Energy Delivered (TWh)	1.63	3.8	7.6	5.3	3.8

connection to GB. The CBA analysis concluded that, due to the technologies involved, the lowest cost option of achieving interconnection with Norway is via a direct interconnection with GB.

In order to assess the potential benefits a reference case was formulated where the renewable output from the JP is 'contained,' or included within the Lead Scenario of the Renewable Energy Strategy. This case is referred to as "contained" renewables in the CBA tables. The CBA results show that a direct onshore to onshore link is the most cost effective way of interconnecting GB with Norway. The capital costs of this option are lower and the savings, including carbon, balancing cost reduction, security of supply and potential reduction in wholesale prices, all contribute to a positive CBA. However, additional renewable generation will only be achieved if the UK enters new renewable JP construction in Norway.

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Achieving interconnection via a wind farm at Dogger Bank may lead to additional renewable generation at Dogger Bank over and above the Lead Scenario of the Renewable Energy Strategy. This case is referred to as "additional" renewables in the CBA tables. As a result the carbon savings are comparable to a direct interconnection, but all other benefits are lower. However, while interconnection via Dogger Bank may be an option (and has been widely commented upon as a 'hub' for a North Sea offshore grid) the reality may differ. Due to the technologies involved our analysis suggests the most cost effective way of connecting offshore wind generation at Dogger Bank (and all other Round 3 sites) may not be via an interconnection, but instead via a direct connection from the wind farm to the UK.

NPV of UK costs and benefits (£m)	500 MW link via Dogger wind farm (500 MW) with 1000 MW link Dogger-GB: 'contained' renewables		500 MW link via Dogger wind farm (500 MW) with 1000 MW link Dogger-GB: 'additional' renewables		Direct Interconnector (500 MW)	
	to 2020	to 2030	to 2020	to 2030	to 2020	to 2030
Carbon	98	400	342	1,395	440	1,794
Balancing cost	12	35	-28	-81	24	70
Back up / Thermal plant	106	270	80	203	213	540
Renewable subsidy	0	0	-447	1,171	0	0
Subtotal	**216**	**705**	**-53**	**346**	**677**	**2,404**
Wholesale price	*20*	*60*	*20*	*60*	*27*	*80*
Total	**236**	**765**	**-33**	**406**	**704**	**2,484**
Additional contribution to renewables target?	Maybe	Maybe	Yes	Yes	Maybe	Maybe

Ireland

Joint Project opportunities between the UK and Ireland exist in the Irish Sea with the potential development of offshore wind in Irish territorial waters. Although it is more cost effective to connect these wind farms to Ireland rather than GB, connecting to the Irish network may require substantial network reinforcements with expected connection dates well into the future. As a result a workable option may be JP development of potential wind farms in Irish waters connected to the UK, rather than Ireland, where an earlier connection date may be possible.

Three key options were considered:

- Direct connection of a wind farm in Irish territorial waters to GB
- A 500 MW interconnection between GB and Ireland via a 1000 MW offshore wind farm
- A direct onshore to onshore interconnection between GB and Ireland

The results of the CBA analysis show that the lowest cost method of achieving interconnection with Ireland (100 km) is via a direct onshore to onshore interconnection using CSC technology.

But, does a direct onshore to onshore interconnection provide greater benefits? The CBA analysis shows that direct onshore to onshore interconnection provides some benefits to the UK in terms of balancing costs, small carbon savings (based on a reduced carbon intensity of generation in the Single Electricity Market (SEM) over time) and reduction in the requirement for thermal plant. Interconnection via a JP in Irish territorial waters will provide greater carbon savings and additional renewable generation.

Interconnection Cost	Offshore wind 1000 MW	Direct Link GB-Ireland 500 MW	GB-Ireland (500 MW) via WF: Wind Farm 1000 MW	GB-Ireland (500 MW) via WF: Wind Farm 500 MW
Cable costs £m	115	67	127	79
Converters £m	254	120	318	227
Total £m	**369**	**187**	**445**	**306**

However, the UK must bear the cost of providing renewable obligation certificate (ROC) support for offshore generation in Irish waters. A JP wind farm in Irish waters connected only to the UK will clearly provide additional renewable generation for the UK's 2020 renewable target and carbon emission reductions, but no other interconnection benefits.

The CBA results suggest that a direct interconnection is the least cost option, but the NPV to the UK (particularly carbon and additional renewables) is lower than interconnection via an offshore wind farm due to the prevailing generation mix in the Irish Single Electricity Market.

NPV of UK costs and benefits (£m)	500 MW wind farms linked via 500 MW link: 'contained' renewables to 2020	to 2030	'additional' renewables to 2020	to 2030	Direct Interconnector (500 MW) to 2020	to 2030
Carbon	0	0	40	166	0	0
Balancing cost	5	13	-20	-58	20	58
Back up / Thermal plant	38	96	12	30	76	193
Renewable subsidy	0	0	-447	1,171	0	0
Subtotal	**42**	**110**	**-415**	**-1,033**	**96**	**251**
Wholesale price	*7*	*19*	*7*	*19*	*13*	*38*
Total	**88**	**225**	**-408**	**-1,014**	**109**	**289**
Additional contribution to renewables target?	No	No	Yes	Yes	No	No

Going forwards, without additional interconnection it is likely that Irish onshore wind generation may become increasingly 'curtailed' for operational considerations and prices in the SEM will become increasingly volatile. Increased interconnection will, in effect, allow Ireland to export excess wind generation – of clear benefit to customers of the SEM (including UK electricity consumers in Northern Ireland).

An attractive alternative that may be the least cost interconnection option is the (direct connection) linked to an *onshore* wind JP in Ireland. This option could allow the UK to realise all the renewable and carbon benefits associated with interconnection via an offshore wind farm, but achieved with lower cost onshore wind generation requiring lower subsidy suport.

However, while developing onshore wind in Ireland is likely to be more cost effective than offshore (as onshore wind is around half the cost of offshore wind) grid, reinforcement in Ireland is likely to be required, with associated time and cost implications.

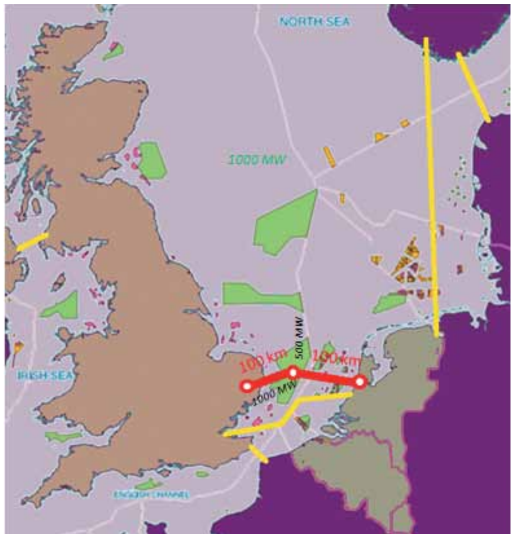
Continental Europe

A further option for JP development may be for the UK to export renewable generation from an offshore wind farm, e.g. Round 3 Norfolk to Continental Europe (Belgium/ Netherlands are only some 100 km to Norfolk R3 area), particularly as Belgium, Denmark and Luxembourg have indicated that they may have a deficit of renewables in 2020 compared to their binding target and could require transfers from another Member State or third country.

However, while UK offshore wind may be an option for Member States in Europe struggling to meet their 2020 renewable targets, it is also likely that statistical transfer of onshore renewables from another country may be a more cost effective option for these countries compared to more costly UK offshore renewables.

A potential cost effective option from a UK perspective might be to realise the benefits of interconnection between the UK and continental Europe by connecting two offshore wind farms in, for example, Round 3 Norfolk and Continental Europe.

NPV of UK costs and benefits (£m)	500 MW link via wind farm (500 MW) with 1000 MW link Wind farm-GB: 'contained' renewables to 2020	to 2030	'additional' renewables to 2020	to 2030	Direct Interconnector (500 MW) to 2020	to 2030
Carbon	47	312	113	639	47	313
Balancing cost	13	31	-11	-40	29	76
Back up / Thermal plant	42	131	16	65	42	131
Renewable subsidy	0	0	-447	1,171	0	0
Subtotal	**103**	**475**	**-329**	**-507**	**118**	**520**
Wholesale price	*7*	*21*	*7*	*21*	*13*	*40*
Total	**110**	**496**	**-322**	**-486**	**131**	**560**
Additional contribution to renewables target?	No	No	Yes	Yes	No (?)	No (?)



The CBA results show that, if a Round 3 wind farm is built in UK waters and another in the waters of continental Europe, then the incremental cost of connecting these two wind farms to create a de facto interconnection could be relatively small.

The CBA of potential interconnections to continental Europe via an offshore wind farm shows that the benefits are smaller than those achieved via a direct interconnection. The smaller benefits arise due to the output of the wind farms reducing the potential arbitrage opportunities between the power markets of the UK and, for example, the Netherlands.

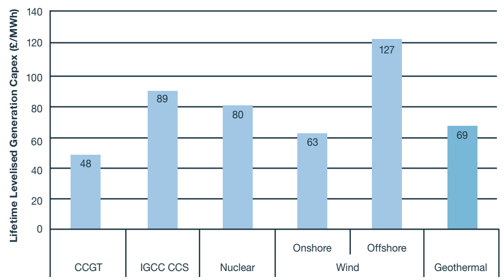
The UK is also unlikely to gain additional renewable generation as the coincidence of wind generation will be almost identical at the two wind farms due to their close proximity.

However, creating an interconnection through linking two existing wind farms is dependent on their construction – ex-post interconnection between two existing windfarms would be considerably less attractive to a developer than their interconnection during construction. Other issues that might frustrate the process include compatibility between voltage levels and potential technology differences between differing manufacturers. A certain level of standardisation would greatly enhance the feasibility of such interconnections between wind farms. Notwithstanding the above, for wind farms in close proximity, the provision of an AC interconnection between them could be attractive as it would allow sharing one of the export links when the other one is unavailable. Although under such arrangements the combined output of both wind farms would be constrained for higher outputs, it would allow exporting output for the majority of time considering wind output patterns. The increased revenue may be attractive compared to the potential costs of the long outage associated with submarine cable repairs.

Overall the benefits of interconnection may be more readily accessed by an onshore to onshore direct interconnection, such as the BritNed interconnector currently under construction. The CBA results suggest that an interconnector with continental Europe would provide benefits from security of supply and balancing cost reduction. However, unless an onshore dedicated JP is developed in Belgium/ Netherlands, carbon reductions or additional renewable generation may not be achieved via a direct interconnection due to the prevailing generation mix in continental Europe. Similarly, the arbitrage power price analysis suggests flows could be finely balanced between imports and exports – suggesting limited downward impact on the GB wholesale price.

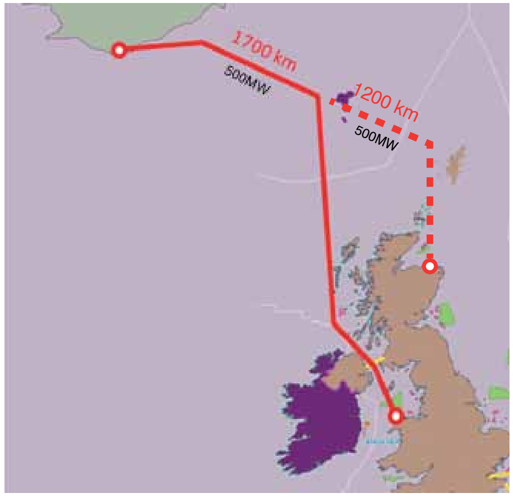
Iceland

A final option for analysis was the potential for the UK to enter a JP with Iceland, developing a 500 MW geothermal plant in Iceland by 2020 with a direct interconnection to the UK. The key driver behind the analysis was the comparative cost of geothermal generation. While the capital costs of geothermal generation are high, the load factor of geothermal generation is also high, at around 90 per cent. As a result geothermal generation is a potentially attractive option.



A number of potential options for connecting the UK to Iceland have been considered in this study.

The analysis of costs suggests that, when the electrical interconnection costs are added to the generation capex, Icelandic geothermal directly connected to the UK is a potentially cost effective renewable option, with the most attractive option a 1,200 km link to Northern Scotland. The potential benefits of interconnecting the UK to Iceland relate



mainly to carbon saved, potential additional contribution to the UK's renewable target (unmonetised) and the reduction in thermal plant that is required to maintain system security.

NPV of UK costs and benefits (£m)	'contained' renewables		'additional' renewables	
	to 2020	to 2030	to 2020	to 2030
Carbon	0	0	220	897
Balancing cost	83	242	0	0
Back up / Thermal plant	54	138	122	309
Renewable subsidy	359	993	689	1,750
Subtotal	**496**	**1,372**	**347**	**544**
Wholesale price	*44*	*116*	*13*	*40*
Total	**540**	**1,488**	**334**	**504**
Additional contribution to renewables target?	No	No	Yes	Yes

However, while the CBA suggests that Icelandic geothermal imported into the UK may be a cost effective option, the project risks of geothermal are high and when combined with a 1,200 km sub sea cable, risks rise again. As a result it may be argued that a project developer may require a higher return for the project.

	CCGT	IGCC CCS	Nuclear	Onshore Wind	Offshore Wind	Geothermal
Capex (£k/kW)	0.6	2.0	2.4	1.2	2.6	2.9
FOC (£/kW/yr)	20	100	57	25	53	28
VOC (£/kWh)	0.002	0.004	0.003	0.0005	0.0005	0.0060
Discount rate	12%	12%	12%	12%	12%	12%
Load factor	80%	80%	80%	30%	39%	91%
Amortisation period	20	30	30	20	20	20
Fuel costs	50p/thm	$100/te				
Carbon	€20/te CO2					
Lifetime levelised cost (£/MWh)	48	89	80	63	127	**69**

IRR	Offshore wind	Direct Link 1,700 km CSC	Direct Link 1,20km CSC	Direct Link 1,200 km CSC	Iceland link via Shetland linking with 500 MW wind farm: With 1000 MW link Shetland to GB	Iceland link via Shetland linking with 500 MW wind farm: With 500 MW link Shetland to GB
10%	1.5	1	0.75	1	0.75	2.75
12%	2	1.5	1	1.5	1.25	3.25
15%	2.75	2.25	1.75	2.25	2	4.5
18.5%	3.5	3	2.25	2.75	2.5	6

In order to investigate these issues, an internal rate of return (IRR) sensitivity analysis was undertaken. At a 12% IRR the ROC support for Icelandic geothermal ranges between 1 and 2.75 ROCs, depending on the cable option considered. At 15% IRR, the ROC support required to support the lowest cost Icelandic imported geothermal options is similar to the ROC support currently awarded to geothermal (2 ROCs/MWh).

However at 18.5% IRR, ROC support for Icelandic options rises above current geothermal support. Geothermal project developers are currently seeking IRRs of around 18.5%. As a result, although apparently a cost effective option, caution must be used when assessing the 'real world' factors influencing potential development.

Another factor that may hamper development is the relatively weak onshore transmission system in Iceland. Any large JP significantly increasing East-West power transfers in Iceland may require onshore reinforcements.

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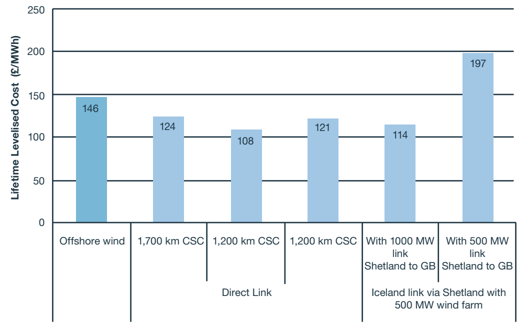
While there is potential for geothermal development in Iceland for export to the UK, we consider that 500 MW by 2020 may be feasible. Current installed geothermal in Iceland is around 500 MW – so doubling this by 2020 represents a challenge in itself. This could be achieved through the development of five 100 MW plants – complicating the co-ordination of the ultimate project but noting that recently 5 geothermal plants of 45 MW capacity were contracted simultaneously in Iceland.

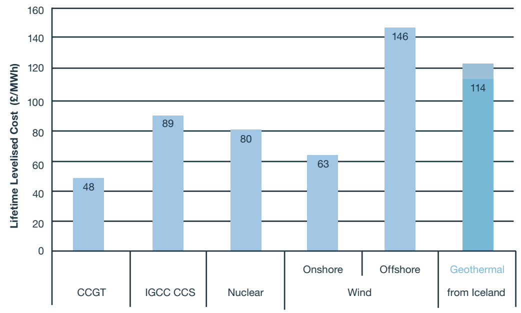
Therefore while geothermal joint project development in Iceland is a potentially cost effective way of achieving additional renewable generation for the UK – the option is limited by the likely extent of geothermal generation in Iceland by 2020 and the risk/reward potential developers will seek.

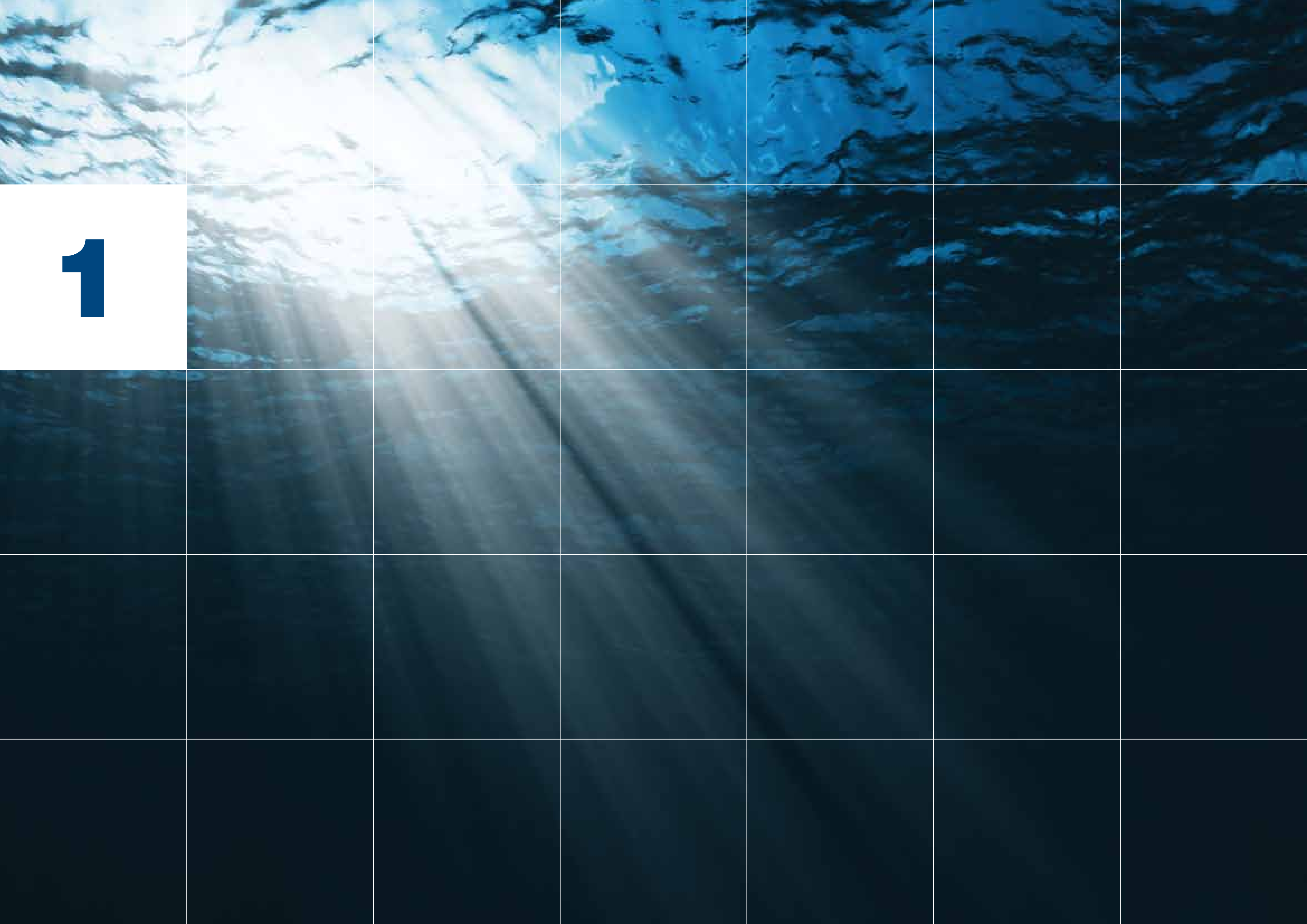
Conclusions

There are clear benefits to the UK of interconnection and JP development – the question is what are the most cost effective ways to achieve these opportunities?
The CBA results suggest:

- An onshore point to point interconnection with Norway could be the most cost effective option for achieving the benefits of interconnection with Norway. However, under the 2009 EU Renewable Energy Directive only Norwegian hydro generation commissioned after the Directive came into force would count towards the UK renewables target. Investing in new hydro or wind projects in Norway may be a JP option for the UK, but cost effectiveness would depend on the availability and economics of such projects. JP development at Dogger Bank with an interconnection offers lower benefits to the UK, and for a wind farm developer, a direct link from Dogger Bank to the UK is the more cost effective option.
- For Ireland – JP development in Irish waters provides limited benefits to the UK – a more cost effective approach to providing additional renewable generation for the UK and the benefits of interconnection would be to invest in onshore JPs in Ireland and provide a direct interconnection to GB.
- For continental Europe – linking two offshore wind farms to create an interconnection could be the most cost effective approach and provide a cost effective 'back up' interconnector. But little new renewable generation is likely to result and the option requires these offshore projects to be built. As a result achieving the benefits of interconnection may be more readily achieved via a direct onshore to onshore interconnection.
- Geothermal generation from Iceland is a potentially cost effective JP development – but will be relatively small scale and high risk.







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1. Introduction

Sinclair Knight Merz (SKM), in association with Deloitte, was appointed by the Department for Energy and Climate Change (DECC) to undertake a high level review of the costs and benefits, from a UK perspective, of developing Joint Projects with third countries and the scope for combined development of an Offshore Grid.

The combination of offshore wind developments increasingly further away from shore in the UK and potential offshore wind growth in neighbouring countries raises the possibility of developing a North Sea grid integrated with offshore wind expansion. Hand in hand with such possible developments is the potential to help the UK meet its ambitious renewable and carbon targets through entering renewable Joint Projects (JP) developments with other countries, both Member States and non Member States.

In order to explore the potential for JP development and of interconnection to be achieved via JP development, we have undertaken a high level cost benefit analysis (CBA) of the technical and economic drivers underpinning such developments. The CBA considers a range of potential Joint Project developments between the UK and third parties. The aim is to help answer, from a UK perspective, two questions:

- Can offshore wind offer a vehicle for cost effective interconnection?
- Does Joint Project development offer a cost effective route to help the UK meet its renewable and carbon targets and possibly also achieve interconnection?

1.1 The UK perspective

The UK has a relatively low level of interconnection at present compared to most other EU Members and a growing contribution from wind generation, anticipated to rise significantly by 2020. Greater interconnection between the UK and third countries is likely to be beneficial (and 10% interconnection is an EU aspiration) and a number of interconnection projects are currently both under construction and in planning.

The provision of interconnection between countries on the continent is relatively low cost, generally involving overhead lines and alternating current (AC) technology.
In comparison interconnection between GB and continental Europe is significantly more costly, requiring offshore cable connections and direct current (DC) technology. JP development may provide the opportunity to achieve greater interconnection between the UK and neighbouring countries, while also contribute to renewable and carbon targets. In principle such concepts seem to make sense, however the main question is whether, from a UK viewpoint, such schemes are technically feasible and attractive from a cost-benefit perspective.

1.2 What is a Joint Project?

The Renewable Energy Directive introduces a number of flexibility mechanisms to enable Member States to meet their 2020 renewable targets, including Joint Project development and statistical transfer schemes. This study has focused on Joint Projects that involve a direct interconnection with the UK. A statistical transfer would occur when a Member State buys renewable energy deployed in another country.

1.3 Joint Project potentials

In order to explore the potential costs and benefits of JP development with interconnection a number of potential JP options have been analysed in detail. These include:

- An offshore wind farm at Dogger Bank connected to the UK and Norway – effectively forming an interconnection and also the costs and benefits of a direct connection with Norway.
- An offshore wind farm in Irish territorial waters connected to the UK (with and without an interconnection to Ireland) and also the costs and benefits of a direct connection with Ireland.
- The connection between an offshore wind farm in UK waters and one in the territorial waters of a Continental European country, forming a de facto interconnection.

- A direct interconnection between the UK and Iceland to directly import onshore geothermal renewable generation.

The aim of the CBA was to assess whether any of the potential JP considered may provide positive net benefits to the UK, including the potential offered for greater interconnection.

1.4 The rationale for interconnection – arbitrage potential

A key rationale for constructing an interconnector is its utilisation – in simple terms those using an interconnector will pay a fee to the developer for each MWh transferred. One way of attempting to evaluate likely flows on an interconnector is to assess the arbitrage potential between the power markets in question. In order to determine the potential for arbitrage between GB and other markets the following were analysed:

- Electricity price arbitrage opportunities based on historic daily half-hourly electricity price data from the APX-UK exchange (formerly UKPX) and hourly data from the Dutch exchange APX-NL and Nordpool which covers Finland, Sweden, Denmark and Norway. The time period covered is 27 March 2001 to 16 December 2009.
- The differential between the electricity price in GB and the Netherlands and between GB and Nordpool was calculated for each hour.

To derive arbitrage opportunities we reduce the differential to account for losses (initially set at 5%) and balancing costs (set at £2/MWh[1]).

- For Ireland historic half-hourly electricity price data (SMP) in Pounds Sterling from the SEM that started operation in November 2007 was used, so the time period covered is from 1 November 2007 to 16 December 2009. A notional £8/MWh was added in each period to reflect the impact of the Capacity Payment Mechanism (CPM).
- The likely impact on arbitrage revenues of the flows produced by offshore wind generation was then calculated; and then
- Estimated likely future revenues from the historic values.

The arbitrage analysis concluded that arbitrage opportunities existed between the UK and the three markets analysed (SEM, Norpool and APX-NL) with the interconnector flowing around 80% of the time. However, the analysis also concluded that interconnection via a wind farm would reduce the interconnector flows by around 40-45% due to the output of the wind farm.

[1] GB BSUoS has averaged approximately £1/MWh to date and this value was doubled to account notionally for balancing costs on both markets.

1. Introduction

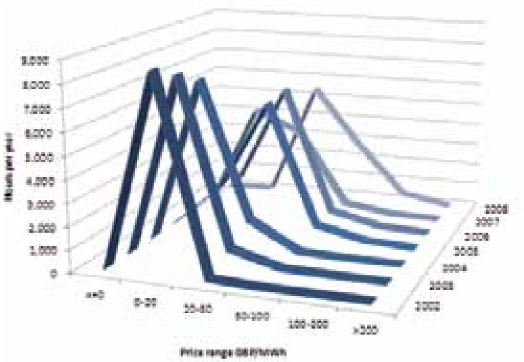
The analysis of arbitrage opportunities has been based on empirical evidence from historic data. To form opinion of future arbitrage opportunities, a view is needed of the impact of potential changes to the generation mix, in particular a greater contribution from intermittent (mainly wind) generation.

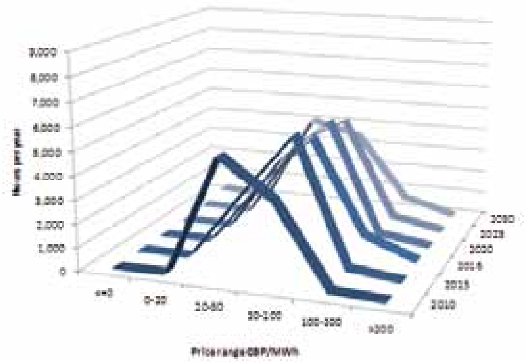
For the GB and SEM market future projections of price volatility were sourced from the results of a recent multi client study[2]. The analysis shows that greater price volatility is expected in the GB market with 2008, a year of uncharacteristic price volatility, potentially representing more closely projected future price volatility.

For Norway it has been assumed as a high level approximation that wholesale electricity price volatility in Nordpool will remain similar to recent history given that expected shifts in generation mix are smaller and interconnection capacity is higher than GB or the SEM.

For the Netherlands, interconnection capacity is lower and expected shifts in generation mix are higher than for Norway. However, in the absence of better information it has been assumed that wholesale electricity price volatility in APX-NL will remain similar to recent history, although this assumption is less robust than for Nordpool.

Further work is required to derive reliable projections of future interconnector revenues, however the arbitrage analysis suggests that sustained growth may be expected.





[2] Implications of Intermittency, Poyry, May 2009

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2. Cost Benefit Analysis of Joint Project options

In order to determine which JP options may be considered beneficial to the UK our high level CBA analysed and quantified a range of potential benefits:

- The impact on the cost of the renewable subsidy – what would be the impact of the JP on total required ROC funding – in simple terms would any JP development reduce the total renewable subsidy costs if more cost effective renewable generation is imported to the UK?
- Wholesale price reduction – would the JP have any downward impact on wholesale prices via the import of lower cost generation?
- Balancing Costs – given the rise in intermittent wind generation anticipated in the UK, would the potential JP increase or decrease the costs of balancing the system?
- Security of Supply – will the JP increase or decrease the need for 'shadow' plant or 'back up' plant required to support intermittent generation? Could it also potentially displace the need for thermal generation in GB?
- Would carbon emissions rise or fall?
  The CBA also considered whether the potential JP may contribute to the UK renewable target – although this benefit was not quantified.

The costs included are:

- Cabling costs – assessing different technologies for the connection of offshore wind and interconnection
- Convertor costs – for both offshore generation and interconnection
- Losses – differing cable technologies have differing losses
- Generation capex costs – In order to undertake a high level CBA of JPs and potential interconnection opportunities, the Lead Scenario outlined in the 2009 RES was used as a comparator against which to assess our JP cases.

The 2009 RES Lead Scenario provided annual values to 2030 for a variety of parameters, including the generation mix, renewable subsidy, balancing costs and wholesale prices. The scenario thus provides the basis for detailed comparison of the JP opportunities while simultaneously providing a robust approach combined with consistency with current DECC policy.

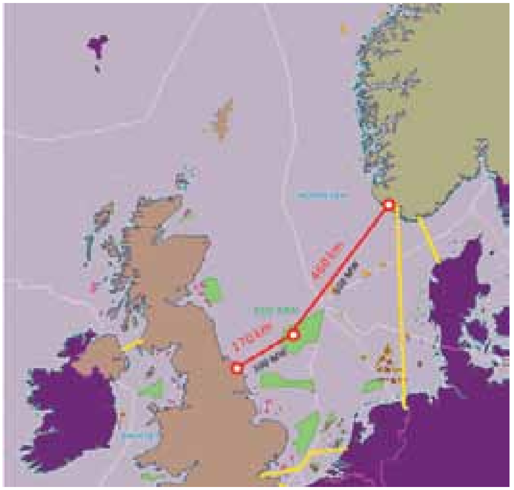
In order to assess the potential benefits, a reference case was formulated where the renewable output from the JP is "contained", or included, in the Lead Scenario of the Renewable Energy Strategy. Another case was also studied where the renewable output from the JP is "additional" or in addition to the contribution from renewables considered in the Lead Scenario of the Renewable Energy Strategy. These cases are labelled accordingly in the CBA tables presented in this report.

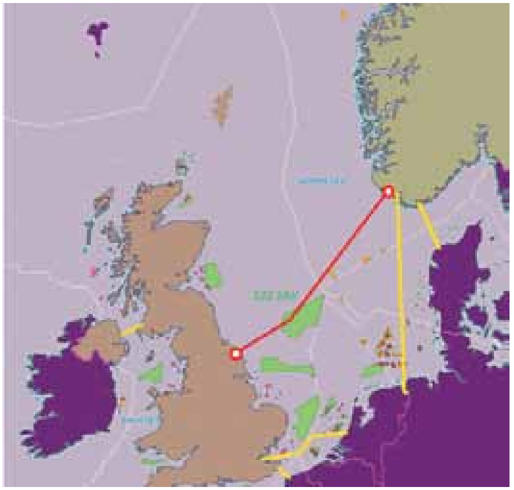
2.1 Norway

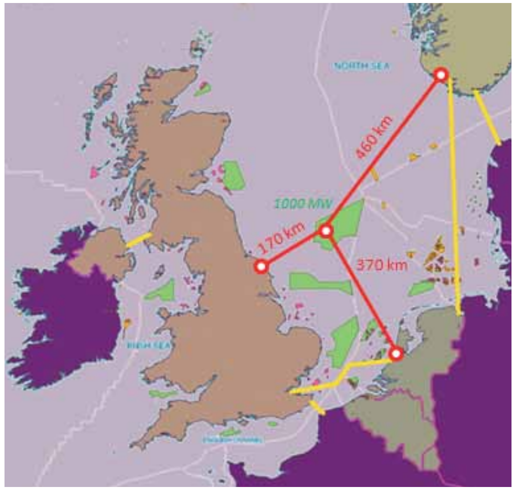
The potential for offshore wind developed at Dogger Bank to provide the impetus for interconnection is a common theme across many studies exploring the potential for a European offshore grid. We investigated the potential to link offshore wind development at Dogger Bank to both the UK and Norway, thus providing a de facto interconnection.

A range of potential JP and interconnection options were considered:

- An interconnection to Norway via Dogger Bank
- A direct onshore to onshore interconnection to Norway
- An interconnection via the Shetland Islands, exploiting the transmission network to connect onshore wind in the Shetlands
- A three way UK-Norway-Benelux interconnection







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How can it be done – technical issues

The technology required to interconnect the UK with Norway via a wind farm differs from that required to directly connect the UK to Norway. Interconnection to Norway via an offshore wind farm at Dogger Bank would require:

- Two direct current (DC) onshore converters and one offshore converter on top of an offshore platform – three converters in total
- For the high voltage DC (HVDC) links, the use of voltage source converter (VSC) technology rather than the less costly and more 'efficient'current source converter (CSC) technology (with lower losses and higher voltage and transfer capabilities). While CSC technology can be used when connecting two strong networks, when connecting a wind farm or more generally a weak network the use of VSC technology is required for technical reasons. However VSC is evolving rapidly and similar efficiency level to CSC in terms of losses performance could be expected within the next five years
- The use of VSC also introduces a size limitation to around 1 GW per DC link module as each DC link can currently only carry about 1 GW. This technical constraint is often not fully explained in many published layouts of the European offshore grid
- Dogger Bank as a 'hub' would require the use of multi-terminal HVDC. While there is no significant experience of such an approach, it remains technically feasible

A direct onshore to onshore interconnection with Norway would involve:

- Two DC converters, both onshore
- The use of CSC technology

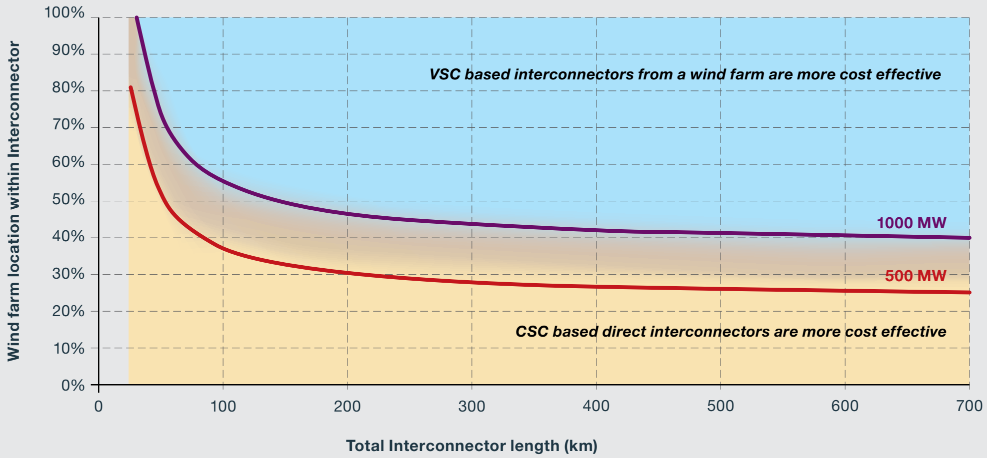
The capital cost of a direct interconnection using CSC technology is lower than using VSC technology, and it is possible to use higher voltages with lower losses and higher link capacities. Furthermore a much longer operational and investment experience of CSC technology exists, which has been the technology of choice for long DC interconnections.

Point to Point DC interconnection

Wind Farm DC Connection

DC interconnection via Wind Farm

Interconnectors: Cheaper direct or from an offshore wind farm?



Generally DC Interconnection between two countries is more cost effective using CSC technology than using VSC technology. For wind farms far from shore, VSC is the preferred connection method. These wind farms could be relatively close to another country. It could therefore be cost effective to provide an interconnection from an existing DC connected wind farm to another country using VSC technology (more expensive but shorter link) than a direct country to country link using CSC technology (longer but cheaper).

A direct interconnector is the lower cost option when the wind farm is closer to the host country than the interconnected country. Also the higher the interconnector rating, the shorter the interconnector distance must be from the wind farm to the interconnected country to be cost effective the provision of a link from the wind farm compared to the cost of a direct interconnection. Specifically, for long interconnectors, a direct link will be a lower cost option if the wind farm is located at a distance greater than about 25% to 40% (depending on output) along the interconnector from the host country.

For example a 500 MW interconnector between GB and Norway via Dogger Bank with a total length of 630 km and the wind farm located about 170 km (26%) from GB could be on the cusp of cost effectiveness compared with a direct interconnection GB-Norway. With a 1000 MW link however a direct connection could be a superior option.

2.1.1 Arbitrage potential GB-Norway

For an interconnector between GB and Norway, arbitrage opportunities exist for around 80% of all trading periods. The Norwegian electricity system is dominated by hydro generation – characterised by a relatively flat pricing profile over the day. Systems with a greater proportion of thermal generation tend to exhibit a more changeable daily pricing profile – with prices moving with demand as increasingly higher cost generation is required to meet increasing demand and vice versa. Given the daily price profile, when the interconnector is flowing, GB would be importing around 70% of the time. However, the pattern is slightly erratic between years, depending on the rainfall in each year and therefore resulting impact on the output of Norwegian hydro – there will be years when the UK exports more to Norway than it imports.

The interconnector volume and value analysis shows that an interconnector of 1 GW capacity between GB and Norway would have generated arbitrage opportunities averaging £92m/year between 27 March 2001 and 16 December 2009. However, connection via a wind farm would reduce these arbitrage revenues by 44% over the same period.

While interconnection with Norway will provide arbitrage potential – the potential for interconnection is limited by Norway's generation supply and demand situation. Norway has some 26.5 GW of available winter generating capacity and on 6 Jan 2010 the demand hit 24 GW at 8am. As a result, in peak periods Norway may only have 1-3 GW of 'spare' capacity and planned new generation is expected to be matched by demand growth. While potential interconnection is planned with the UK, other links are also planned with Northern Europe.

Therefore, while there are benefits to GB of interconnection with Norway in terms of adding to security of supply, the Norwegian system can perhaps support only a further 1 GW link to the UK above the 1.5 GW link planned to Germany and maintain security of supply across the interconnected countries. Interconnection aids security of supply, but 'spare' capacity must be available across the interconnected system somewhere to maintain security of supply.

2.1.2 Infrastructure Costs

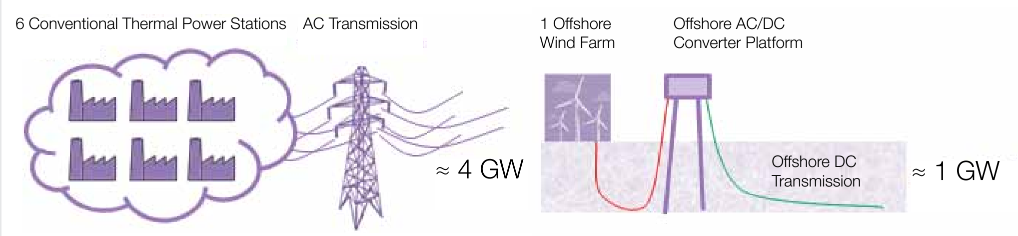
To determine the costs of direct interconnection via a joint project wind farm at Dogger Bank we considered the following:

- 500 MW direct onshore to onshore connection
- 1000 MW direct onshore to onshore connection
- 500 MW link Norway to a 500 MW wind farm a Dogger Bank linked by a 1000 MW connection to GB
- 500 MW link Norway to a 500 MW wind farm at Dogger Bank linked by a 500 MW connection to GB

Dogger Bank as an offshore 'hub?'

Much has been made of the potential for the Dogger Bank to act as a 'hub' for the development of a North Sea offshore grid. The rationale behind the 'hub' approach appears to be based on the principle of onshore transmission lines that are usually alternating current (AC) technology, where a 400 kV overhead line is able to carry the power of up to about 6 large conventional thermal power plants. In essence the power plant capacity is small compared to line capacity and so aggregating multiple stations on a single line makes economic sense.

However in comparison, an offshore wind farm connected via high voltage direct current technology (HVDC) with VSC converters and cable capacity, is restricted to carrying only 1 large offshore wind farm (1 GW). So, unlike the onshore situation and notwithstanding other operational security issues, the offshore wind farm capacity would typically be sized to match the DC module capacity. The result is that aggregating multiple similar large wind farms is not possible in the same way as it would be onshore as each would require additional DC links.



So we conclude that the offshore power hub concept is questionable with current VSC DC technology as one HVDC link per large wind farm is required and so there are no apparent "power hubbing" economies of scale. In addition such aggregation would be limited by system operation safety reasons due to the potential simultaneous loss of generation in case of faults within the interconnected DC links. Development of HVDC breakers may alleviate some of this constraint. While many studies of the potential for a European offshore grid show single lines between an offshore hub and receiving countries, in practice many "lines" should be drawn to reflect the VSC DC technology capacity constraints in the short-medium term.

The size of the configurations outlined above is driven by the available VSC module sizes. The results show that a 1000 MW onshore to onshore direct connection is the most cost effective option, delivering the greatest energy flows at the lowest cost.

If connecting via Dogger Bank, then a 500 MW link from Norway to a 500 MW wind farm at Dogger Bank, followed by a 1000 MW connection to GB is the most cost effective option as the 1000 MW link is sufficient in size to prevent the output from the wind farm constraining the flows on the interconnector and thus arbitrage revenues.

2.1.3 Costs and benefits from a UK perspective

While much Norwegian hydro generation is existing and thus cannot contribute to the UK's renewable target,[3] hydro generation is a low carbon, baseload form of electricity generation that can provide positive benefits to the UK in the form of carbon savings, security of supply, balancing cost reductions and potential wholesale price reductions.

Two cases were analysed in detail – the lowest cost direct interconnection (1000 MW) and the lowest cost option for interconnection via Dogger Bank (500 MW link Norway to a 500 MW wind farm at Dogger Bank linked by a 1000 MW connection to GB).

The CBA assessed the Net Present Value (NPV) of the costs and benefits associated with the two investment options analysed – assuming the links are commissioned in 2016. The CBA compared each case to the RES Lead Scenario – therefore, for example, carbon savings or balancing cost reductions realised are vis-a-vis those outlined in the RES Lead Scenario.

The results of the CBA analysis showed there are substantial benefits to the UK of providing an interconnection to Norway. The UK would benefit from interconnection with Norway via;

- Carbon savings
- Balancing costs
- Security of supply
- Wholesale price

The greatest benefit to the UK, in terms of the variables identified above, is realised from a 1000 MW direct connection with Norway – with the benefits dominated by carbon savings resulting from importing hydro electricity. Security of supply benefits are also realised via the reduction in thermal plant needed in the UK to maintain system security. Some balancing cost benefits are also made. Wholesale price reductions have not been modelled in detail[4] – the figures shown throughout the analysis are indicative.

Interconnection Cost	Offshore wind 500 MW	Direct Link GB-Norway		GB-Norway (500 MW) via WF	
		500 MW	1000 MW	Dogger-GB 1000 MW	Dogger-GB 500 MW
Cable costs £m	50	347	451	505	413
Converters £m	170	120	180	254	227
Total £m	**220**	**467**	**631**	**759**	**640**
Energy delivered	1.63	3.8	7.6	5.3	3.8

Connection via Dogger Bank leads to less electricity imported from Norway (the link to Norway is only rated at 500 MW) and subsequently smaller interconnection benefits. The addition of wind generation at Dogger Bank also leads to a reduction in balancing cost benefits.

However, while the costs of interconnection to Norway could be lower with a direct interconnection, the UK may not benefit from additional renewable generation imports that could contribute towards the 2020 target as existing Norwegian hydro would not count towards the UK renewables target under the EU Renewable Energy Directive[3]. There may be potential for the UK to enter onshore hydro Joint Projects in Norway, the cost effectiveness of which will be determined by the economics of capital intensive hydro development in Norway.

[3] The EU Renewables Directive only 'new' JP renewable generation may count towards a Members State's renewable target
[4] In order to determine projected wholesale price reductions the GB and Nordpool electricity systems would need to be modelled in detail, which is beyond the scope of this study. However, the analysis of generation costs and GB and Nordpool empirical evidence suggests that overall wholesale price reductions are likely to occur for GB

NPV of UK costs and benefits (£m)	500 MW link via Dogger wind farm (500 MW) with 1000 MW link Dogger-GB 'contained' renewables to 2020	to 2030	'additional' renewables to 2020	to 2030	Direct Interconnector (1000 MW) to 2020	to 2030
Carbon	98	400	342	1,395	440	1,794
Balancing cost	12	35	-28	-81	24	70
Back up / Thermal plant	106	270	80	203	213	540
Renewable subsidy	0	0	-447	1,171	0	0
Subtotal	**216**	**705**	**-53**	**346**	**677**	**2,404**
Wholesale price	*20*	*60*	*20*	*60*	*27*	*80*
Total	**236**	**765**	**-33**	**406**	**704**	**2,484**
Additional contribution to renewables target?	Maybe	Maybe	Yes	Yes	Maybe	Maybe

2.1.4 Summary

The CBA shows that the direct link is the most cost effective way of interconnecting GB with Norway. However, unless the UK enters onshore JPs with Norway, no additional renewable benefit will be realised from this direct connection.

With present technology the most cost effective way of connecting offshore wind generation at Dogger Bank and all other Round 3 sites is direct connection to the UK.

Given the technology constraints, it does not seem particularly attractive that Dogger Bank becomes a 'hub' for a European offshore grid – particularly as the individual links from Dogger Bank would be limited to about 1 GW in capacity.

2.2. Ireland

2.2.1 Potential sites

Joint Project development opportunities also exist in the Irish Sea with the potential development of offshore wind close to shore in Irish territorial waters. While inevitably it is more cost effective for the offshore wind developer to connect such wind farms to Ireland rather than GB, connecting the proposed developments to the Irish network may require substantial network reinforcements with expected connection dates well into the future. As a result one option may be JP development of potential wind farms in Irish waters but connected to the UK, rather than Ireland, where an earlier connection date may be possible in some cases.

Three key options were considered in more detail:

- Direct connection of a wind farm in Irish territorial waters to GB
- An interconnection between GB and Ireland via an offshore wind farm
- A direct onshore to onshore interconnection between GB and Ireland

The CBA in this case has been based on a 1000 MW wind farm in Irish territorial waters, potentially combined with a 500 MW interconnection to Ireland.

2.2.2 Arbitrage potential GB-SEM

While the data series analysed for the SEM is relatively short given that the SEM only began operating in 2007, our analysis of the potential interconnector flows based on arbitrage opportunities indicates that the interconnector will be utilised for around 90% of all trading periods. For 21% of the time power will flow on the interconnector from Ireland to GB, for 69% of the time the flow would be from GB to Ireland, with no flow for 10% of the time.

The interconnector volume and value analysis shows that an interconnector of 1GW capacity between GB and Ireland would have generated arbitrage opportunities averaging £114m/year between 1 November 2007 and 16 December 2009. However, connection via a wind farm would reduce these revenues by around 40%.

2.2.3 Infrastructure Costs

The CBA analysis shows that the least cost option of achieving a JP in Irish territorial waters is to directly connect a wind farm in Irish territorial waters to GB. The least cost option for achieving interconnection between GB with Ireland is via a direct onshore to onshore link[5].

[5] The proposed East West interconnector is based on VSC technology due to space constraint issues and longer outline route (75 km land cable and 186 km sea cable) results in much higher capital cost estimate (up to €400m)

Again, as with Norway, the issue of differing technology requirements drives costs. A joint offshore wind farm project with interconnection between GB and Ireland requires:

- For the high voltage direct current (HVDC) links, the use of VSC technology rather than the less costly and more 'efficient' CSC technology (with lower losses and higher voltage capabilities). While CSC technology can be used when connecting two strong networks, when connecting a wind farm or more generally a weak network the use of VSC technology is required for technical reasons. A potential advantage is that certain wind farms close to shore and suitable network sites in Ireland may be connected to Ireland using AC.

- The use of VSC also introduces a size limitation to around 1 GW per DC link module as each DC link can currently only carry about 1 GW.

A direct onshore to onshore interconnection with Ireland would involve:

- Two DC converters, both onshore
- The use of CSC technology

Both factors combine to lead to lower capital cost and reduced losses, together with higher voltages and higher capacities as indicated earlier.

Interconnection Cost	Offshore wind (1000 MW)	Direct Link GB-Ireland 500 MW	GB-Ireland (500 MW) via WF: Wind Farm 1000 MW	GB-Ireland (500 MW) via WF: Wind Farm 500 MW
Cable costs £m	115	67	127	79
Converters £m	254	120	318	227
Total £m	**369**	**187**	**445**	**306**

2.2.4 Costs and benefits from a UK perspective

From the UK's perspective a JP wind farm development in Irish territorial waters connected to the UK rather than Ireland will provide benefits in the form of additional renewable generation for the UK's 2020 renewable target and carbon emission reductions if wind output displaced thermal generation. However, the JP option in Irish territorial waters would clearly provide no wider benefits from interconnection.

The JP in Irish territorial waters as a vehicle for interconnection between the UK and Ireland was also considered. Our analysis indicated that the benefits to the UK that might arise from interconnection via the wind farm would include; additional renewable generation; carbon reductions; security of supply and; wholesale price implications.

As a comparison the benefits associated with a direct onshore to onshore interconnection have also been considered. Direct onshore to onshore interconnection provides some benefits to the UK in terms of balancing costs, small carbon savings (based on a reduced carbon intensity of generation in the Single Electricity Market) and reduction in the requirement for thermal plant.

Greater benefits to the UK are achieved through interconnection via a JP in Irish territorial waters – with the bulk of the benefits accruing from additional carbon savings from the connection of a 1,000 MW wind farm, together with the unmonetised additional renewable generation contributing to the UK's 2020 target.

The arbitrage analysis outlined above suggests that, in the medium term, Ireland will initially be mainly importing (75% of time by 2020, reducing to 55% by 2030[6]), with a correspondingly marginal reduction in electricity wholesale prices. When exports from the Single Electricity Market to GB are made (20% of time by 2020, rising to 40% by 2030) the impact on the electricity wholesale price in the SEM is likely to be upward.

Other benefits to Ireland include security of supply, with additional interconnection offering reserve capacity while exporting or idle and operating capacity while importing.

[6] Implications of Intermittency, Poyry, May 2009

NPV of UK costs and benefits (£m)	500 MW link via wind farm (500 MW) with 1000 MW link Wind farm-GB					
	'contained' renewables		'additional' renewables		Direct Interconnector (500 MW)	
	to 2020	to 2030	to 2020	to 2030	to 2020	to 2030
Balancing cost	13	31	-11	-40	29	76
Back up / Thermal plant	42	131	16	65	42	131
Renewable subsidy	0	0	-447	1,171	0	0
Subtotal	**103**	**475**	**-329**	**-507**	**118**	**520**
Wholesale price	*7*	*21*	*7*	*21*	*13*	*40*
Total	**110**	**496**	**-322**	**-486**	**131**	**560**
Additional contribution to renewables target?	No	No	Yes	Yes	No (?)	No (?)

2.2.5 Summary

JP development in Irish territorial waters may help the UK meet its renewable target and reduce carbon emissions – but with no cost advantages.

Combining offshore wind with interconnection has a positive CBA – with most of the benefits accruing from carbon savings, with benefits also from reduced thermal plant requirement to maintain security of supply in GB. For GB the impact on wholesale prices will be limited initially, with the UK exporting more than it imports. However, while combining a JP with interconnection has a positive CBA, a lower cost route to achieving interconnection would be via a direct onshore to onshore interconnector between GB and Ireland.

Flows on the interconnector will initially be dominated by exports from GB to the SEM. However, over time as the volume of wind in Ireland rises, this position is likely to reverse – beyond 2020 we expect Ireland to become net exporter in winter, when wind output is high, and a net importer in summer when wind output is lower.

Without additional interconnection it is likely that Irish wind generation may become increasingly 'curtailed' for operational considerations and prices in the SEM will become increasingly volatile. Increased interconnection will, in effect, allow Ireland to export excess wind generation – of clear benefit to customers of the SEM (including UK electricity consumers in Northern Ireland).

The CBA results suggest that there are benefits of additional interconnection between GB and the SEM. A direct interconnection is the least cost option, but the total benefits are lower than interconnection via an offshore wind farm due to the prevailing generation mix in the SEM. In simple terms interconnection via an offshore wind farm reduces carbon emissions in the UK due to the output of the wind farm – importing electricity from the SEM will be based on its thermally dominated generation mix.

An optimum option would be a direct connection linked to a JP of onshore wind generation in Ireland. This option would allow the UK to realise all the renewable and carbon benefits associated with interconnection via an offshore wind farm.

Developing onshore wind in Ireland is likely to be more cost effective than developing joint projects offshore in Irish territorial waters as onshore wind is around half the cost of offshore wind and therefore requires less renewable subsidy support.

However higher onshore development in Ireland would likely trigger additional reinforcements to the Irish onshore network, adding to costs and introducing some development risks. Exploring this option would also require consenting regulatory structures between the two markets. It would also be difficult to account JPs onshore if not directly connected and exclusive which then could negate potential interconnection benefits.

2.3 Continental Europe

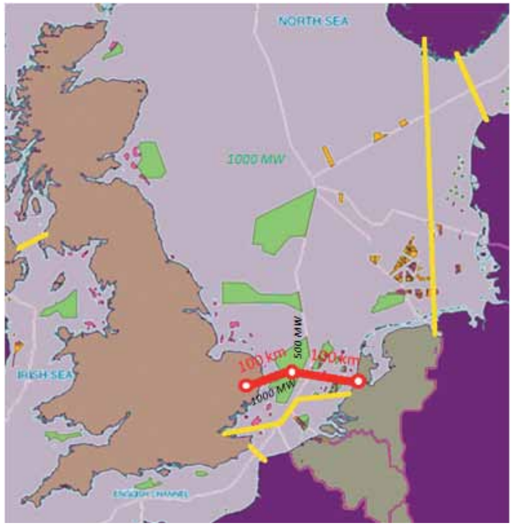
Another alternative for JP development may be for the UK to export renewable generation from an offshore wind farm in Round 3 Norfolk (Belgium/Netherlands are only some 100 km to Norfolk R3 development area), particularly as Belgium, Denmark and Luxembourg have indicated that they may have a deficit of renewables in 2020 compared to their binding target and could require transfers from another Member State or third country. However, it is also likely that statistical transfer of onshore renewables from another country may be a more cost effective option for these countries to achieve their targets than more costly UK offshore renewables.

Another option may be to realise the benefits of interconnection between the UK and continental Europe by connecting two offshore wind farms in, for example, Round 3 Norfolk and the Netherlands. The CBA results show that, if a Round 3 wind farm is built in UK waters and another in the waters of continental Europe (Netherlands), then the incremental cost of connecting these two wind farms to create a de facto interconnection is relatively small.

2.3.1 Arbitrage potential GB-Netherlands

Our analysis indicates that an interconnector between the GB and Netherlands is likely to flow a little below 80% of all trading periods. When the interconnector is flowing, the GB market will be importing around 50% of the time.

The interconnector volume and value analysis shows that an interconnector of 1GW capacity between GB and the Netherlands would have generated arbitrage opportunities averaging £87m/year between 27 March 2001 and 16 December 2009. However, again connection via a wind farm reduces these revenues by around 40%.



2.3.2 Europe CBA

The creation of an interconnection to continental Europe via an offshore wind farm in Round 3 Norfolk will lead to benefits to the UK in terms of security of supply, balancing cost reductions and carbon savings. However these savings will be smaller than those achieved via a direct interconnection due to the output of the wind farms reducing the arbitrage opportunities between the UK and the Netherlands. The UK is also unlikely to gain additional renewable generation as the coincidence of wind generation will be almost identical at the two wind farms due to its likely relatively close proximity.

Given that the overall cost of creating the interconnector will also be relatively low – indicative results suggest that the CBA is strongly positive – suggesting that linking two close wind farms is a cost effective way of achieving the benefits of interconnection. However, linking two existing wind farms is dependent on their construction and therefore may be frustrated by this requirement notwithstanding other technical issues such as compatibility between voltage levels and potentially technology from different manufacturers. A certain level of standardisation would greatly enhance the feasibility of such interconnections.

As a result the benefits of interconnection may be more readily accessed by an onshore to onshore direct interconnection, such as the BritNed interconnector currently under construction. The CBA results suggest that an interconnector with continental Europe would provide benefits from security of supply and balancing cost reduction. However, unless an onshore dedicated joint project is developed in Belgium/Netherlands, carbon reductions or additional renewable generation may not be achieved via a direct interconnection due to the prevailing generation mix in continental Europe. Similarly, the arbitrage analysis suggests flows could be finely balanced between imports and exports – suggesting limited downward impact on the GB wholesale price.

NPV of UK costs and benefits (£m)	500 MW wind farms linked via 500 MW link: 'contained' renewables to 2020	'contained' renewables to 2030	'additional' renewables to 2020	'additional' renewables to 2030	Direct Interconnector (500 MW) to 2020	Direct Interconnector (500 MW) to 2030
Carbon	0	0	40	166	0	0
Balancing cost	5	13	-20	-58	20	58
Back up / Thermal plant	38	96	12	30	76	193
Renewable subsidy	0	0	-447	1,171	0	0
Subtotal	**42**	**110**	**-415**	**-1,033**	**96**	**251**
Wholesale price	*7*	*19*	*7*	*19*	*13*	*38*
Total	**88**	**225**	**-408**	**-1,014**	**109**	**289**
Additional contribution to renewables target?	No	No	Yes	Yes	No	No

2.3.3 Joint project development with Benelux via Dogger Bank

Another option considered is to develop a JP with Benelux at Dogger Bank with an interconnection. However, this option was discounted as less costly 'near to their country' alternatives would seem to exist for Benelux.

For Germany, if Dogger Bank is developed, then again a connection between offshore wind farms may provide a route for a cost effective interconnector – but this requires the construction of offshore wind at Dogger Bank and at the furthest from shore sites in German territorial waters.

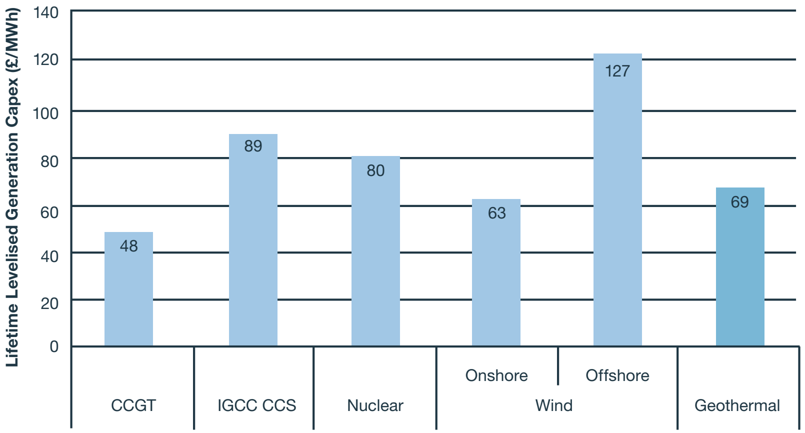
2.4 Iceland

Consideration of potential onshore JPs with a direct interconnection to the UK was then expanded to include Iceland. We evaluated the potential to develop 500 MW of geothermal plant in Iceland by 2020 with a direct interconnection to the UK.

The key driver behind the Icelandic option is the comparative cost of geothermal energy. While the capital costs of geothermal generation are high, the load factor of geothermal generation is also high, at around 90 per cent. As a result geothermal generation is a potentially attractive option, with lifetime levelised costs for generation capex around half those of offshore wind. Given the high load factor of geothermal and the assumption that Icelandic JP geothermal will be exporting to the UK, arbitrage opportunities are low.

Iceland currently has around 565 MW of geothermal capacity, but the potential to develop up to 4.3 GW of geothermal over the next 50 years. The potential output of 4.3 GW of geothermal power would be some 35 TWh, compared to 4 TWh generated in 2008. While the potential for geothermal development in Iceland is relatively large, we consider the development of only 500 MW of geothermal for export to the UK achievable by 2020 – probably requiring the development of five 100 MW geothermal power plants. Given its high load factor, 500 MW of geothermal generation would generate the same amount of electricity as around 1.1 GW of offshore wind.

However, while the levelised cost of geothermal is attractive, clearly Icelandic generation must be exported the considerable distance to the UK – so the cost of interconnection from Iceland to the UK must be added to the generation capex. Two interconnection options were considered – a 1,700 km link to North Wales and a 1,200 km link to the North East of Scotland. To put this distance in context, 1700 km radius from London (similar distance to Iceland-Wales cable route) covers most of Western Europe.



	CCGT	IGCC CCS	Nuclear	Onshore Wind	Offshore Wind	Geothermal
Capex (£k/kW)	0.6	2.0	2.4	1.2	2.6	2.9
FOC (£/kW/yr)	20	100	57	25	53	28
VOC (£/kWh)	0.002	0.004	0.003	0.0005	0.0005	0.0060
Discount rate	12%	12%	12%	12%	12%	12%
Load factor	80%	80%	80%	30%	39%	91%
Amortisation period	20	30	30	20	20	20
Fuel costs	50p/thm	$100/te				
Carbon	€20/te CO2					
Lifetime levelised cost (£/MWh)	48	89	80	63	127	**69**

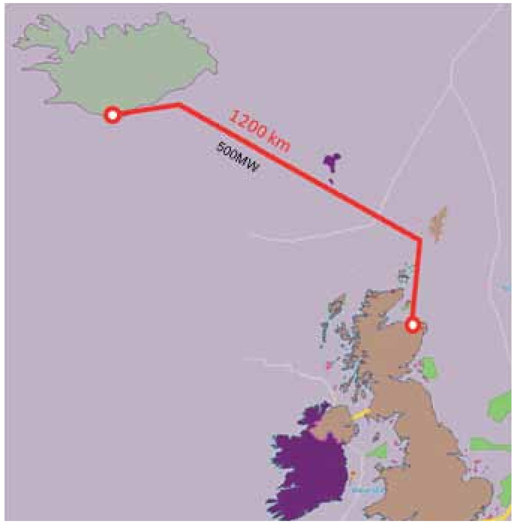
The longest existing HVDC submarine cable installed to date is NorNed at 580 km. As a result project risk issues surround the potential development of a 1,200-1,700 km subsea cable.

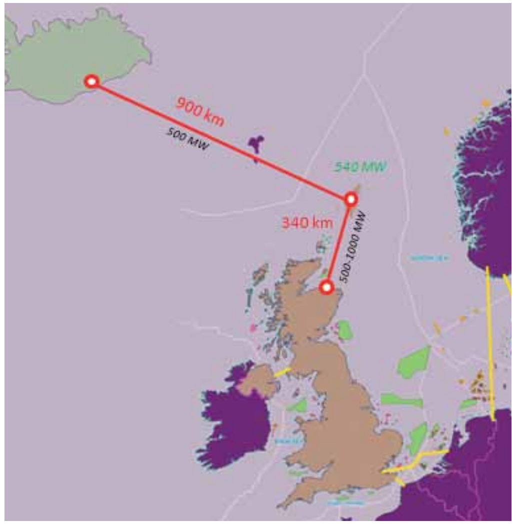
2.4.1 Infrastructure Costs

The cost of a direct link between the UK and Iceland would be around £800 m for the 1,200 km route and about £1 bn for the 1,700 km cable. An alternative lower cost cable option may be to link the cable to the Shetlands. The rationale for this approach is the proposed onshore Shetland Wind farm (540 MW) with the connection assets cost to connect this proposed windfarm thus considered sunk (500 MW). Linking to Iceland via the Shetlands raises two issues:

- VSC technology would be used – with higher losses and lower voltages for connection to Iceland
- A 500 MW link between the Shetlands and Scotland would lead to constraining the output of geothermal as the link would be needed to accommodate both the 540 MW wind farm and the 500 MW geothermal plant

As a result an alternative option was studied consisting of a 1,000 MW link from the Shetland to Scotland – costing more but leading to no constraints on geothermal output.





The results of the CBA analysis suggest that, when the electrical interconnection costs are added to the generation capex costs, Icelandic geothermal directly connected to the UK is a potentially cost effective renewable option. The particularly attractive option is the 1,200 km link to Northern Scotland.

However, while the project uncertainties of geothermal developments are high, they are quantifiable. However, project risk substantially increases when combined with a 1,200 km sub sea cable. As a result it may be argued that a project developer may require a higher internal rate of return (IRR) for the project.

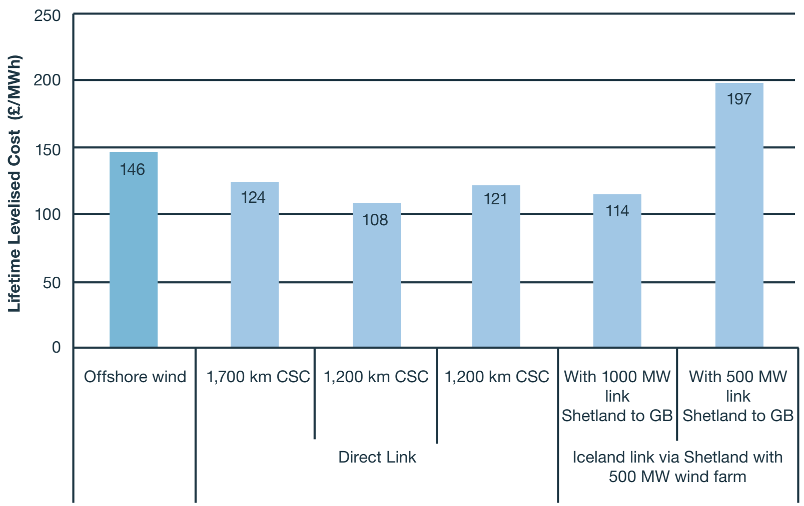
		Direct Link			Iceland link via Shetland linking with 500 MW wind farm	
	Offshore wind	1,700 km CSC	1,200 km CSC	1,200 km VSC	With 1000 MW link Shetland to GB	With 500 MW link Shetland to GB
Capex (£/kW)	3.05	4.99	4.43	4.74	4.65	4.21
Losses	3.9%	10.9%	8.2%	12.9%	9.7%	6.5%
Load Factor	**37%**	**81%**	**83%**	**79%**	**82%**	**43%**
Lifetime levelised cost	146	124	108	121	114	197
Resulting ROC support	2	1.5	1	1.5	1.25	3.25

2.4.2 IRR sensitivity analysis

We undertook a range of sensitivity analyses using varying internal rates of return (IRR) of 12% for offshore wind and 15-18.5% for geothermal generation imported from Iceland. Our analysis concluded that, at a 12% IRR, the ROC support required for Icelandic geothermal ranges between 1 and 2.75 ROCs, depending on the cable option considered.

At 15% IRR, the ROC support required to support the lowest cost Icelandic imported geothermal options are similar to the ROC support currently awarded to geothermal (2 ROCs/MWh).

However at 18.5% IRR, ROC support for Icelandic options rises above current geothermal support. Geothermal project developers are currently seeking IRRs of around 18.5%.



IRR	Offshore wind	Direct Link			Iceland link via Shetland linking with 500 MW wind farm	
		1,700 km CSC	1,200 km CSC	1,200 km VSC	With 1000 MW link Shetland to GB	With 500 MW link Shetland to GB
10%	1.5	1	0.75	1	0.75	2.75
12%	2	1. 5	1	1.5	1.25	3.25
15%	2.75	2.25	1.75	2.25	2	4.5
18.5%	3.5	3	2.25	2.75	2.5	6

As a result, although apparently a cost effective option, caution must be used when assessing the ‘real world’ factors influencing potential development, in particular the risks associated with geothermal development costs in Iceland and the risk of a 1,200-1,700 km sub sea cable.

2.4.3 Costs and benefits from a UK perspective

The creation of geothermal JP with Iceland will lead to benefits to the UK in terms of security of supply, balancing cost reductions, additional renewable generation, wholesale prices and carbon savings. To determine the overall benefits associated with importing geothermal generation from Iceland we assessed two options:

- Icelandic geothermal generation integrated in the 2009 RES Lead scenario
- Icelandic geothermal generation in addition to the 2009 RES Lead scenario

The CBA results show that the potential benefits to the UK of importing geothermal generation from Iceland are particularly strong in terms of carbon saved and reduction in thermal plant required to maintain system security.

Benefit NPV (£m)	'contained' renewables 2020	'contained' renewables 2030	'additional' renewables 2020	'additional' renewables 2030
Carbon	0	0	220	897
Balancing cost	83	242	0	0
Back up / Thermal plant	54	138	122	309
Renewable subsidy	359	993	689	1,750
Subtotal	**496**	**1,372**	**347**	**544**
Wholesale price	*44*	*116*	*13*	*40*
Total	**540**	**1,488**	**334**	**504**
Additional contribution to renewables target?	No	No	Yes	Yes

2.4.4 Other factors

Iceland has a relatively weak transmission system with, in simple terms, two main load areas with a relatively weak 132kV interconnection ring. Any large joint project significantly increasing East-West power transfers would require onshore reinforcements. The South West and East are the strongest areas for connection although are likely to involve offshore routing initially towards the East to avoid deep water areas to the south of Iceland.

Landing an additional 500 MW of generation in North East Scotland will have implications for onshore transmission to the demand centres in the South of England. The analysis of the implications for the GB grid show that some constraints are likely on generation flows from Scotland over the period to 2020. Without the Iceland link constraints are likely for up to 5% of the time by 2020 (even after the construction of the second planned offshore links between Scotland and England – the Eastern link). With the addition of the 500 MW Iceland link, by 2020 constraints could appear for up to 10% of the time.

However, renewables should have priority access over thermal generation. In addition, after 2020, following closure of several conventional thermal generation sites in Scotland then the constraints disappear.

2.4.5 Summary

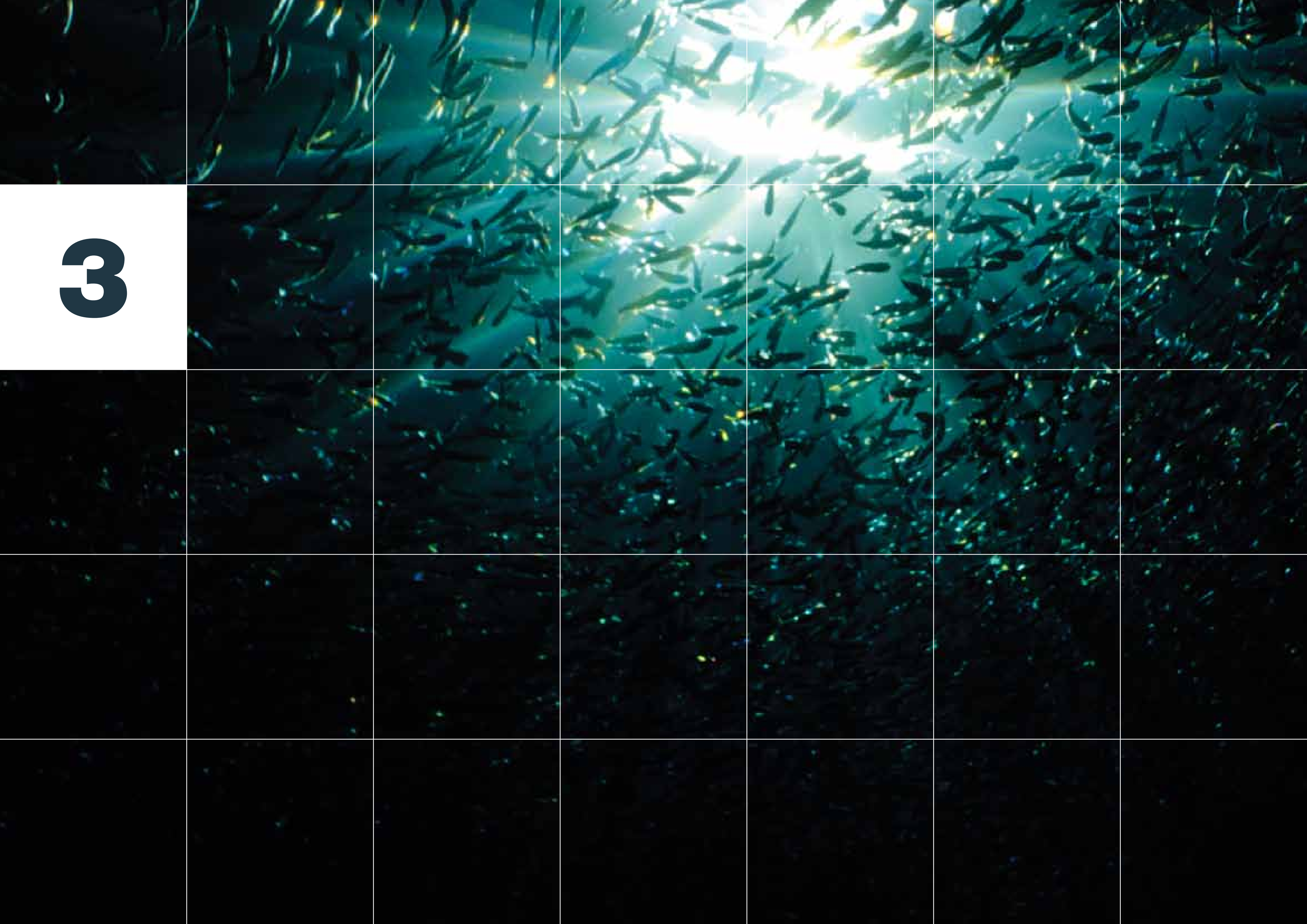
While there is potential for geothermal development in Iceland for export to the UK, we consider that 500 MW by 2020 may be a feasible limit. Current installed geothermal in Iceland is around 500 MW – so doubling this by 2020 represents a challenge in itself. We also assume five 100 MW plants will be developed – complicating the co-ordination of the ultimate project but noting that recently 5 geothermal plants of 45 MW capacity were contracted simultaneously.

Another crucial component is the assumed internal rate of return (IRR) for the geothermal project. The CBA analysis results above are based on an IRR of 12 per cent, in common with that applied to offshore wind. However, it is likely that development risks associated with bringing five 100 MW geothermal plants on line coupled with the risk and contractual complexity of funding a 500 MW, 1,200 km subsea cable (over twice as long than the currently longest subsea cable) are likely to require a higher IRR than 12 per cent.

Therefore while geothermal JP development in Iceland is a potentially cost effective way of achieving additional renewable generation – the option is limited by the likely extent of geothermal generation in Iceland by 2020 and the reward potential developers will seek.

So this is a potentially high risk project, but potentially also it could be a cost effective way of achieving additional renewable generation.

3



3. CBA Conclusions summary

There are clear benefits to the UK of interconnection and JP development – the question is what is the most cost effective way to achieve this opportunities? The CBA results suggest:

- An onshore point to point interconnection with Norway would be the most cost effective option for achieving the benefits of interconnection with Norway. However, existing Norwegian hydro would not count towards the UK renewables target under the 2009 EU Renewable Energy Directive. Investing in new hydro or wind projects in Norway may be a JP option for the UK, but cost effectiveness would depend on the availability and economics of such projects. JP development at Dogger Bank with an interconnection offers lower benefits to the UK, and for a wind farm developer, a direct link from Dogger Bank to the UK is likely to be the more cost effective option.
- For Ireland – JP development in Irish waters may only provide limited benefits to the UK – a more cost effective approach to providing additional renewable generation for the UK and the benefits of interconnection could be to invest in onshore JPs in Ireland and provide a direct interconnection to GB.
- For continental Europe – linking two offshore wind farms to create an interconnection could be the most cost effective approach and provide a cost effective 'back up' interconnector. But little new renewable generation is likely to result and the option requires these offshore projects to be built. As a result achieving the benefits of interconnection may be more readily achieved via a direct onshore to onshore interconnection.
- Geothermal from Iceland is a potentially cost effective JP development compared to offshore wind – but will be relatively small scale and high risk.

3.1 Technical observations

In the assessment of JPs involving integrated development of offshore wind farms in offshore grids it is important to take into account not only the economic considerations but also the technical constraints involved. These arise from the capacity limitations of DC transmission technology and the operational considerations regarding the security of supply of the interconnected grids.

The most cost effective method of connecting wind farms far from shore is using VSC DC technology. Currently VSC DC technology is limited to around 1 GW per link. As a result there could be reduced attractiveness in integrating wind farms with interconnections. In many cases the benefits of interconnection are likely to be achieved more efficiently via conventional direct onshore point to point interconnections using conventional CSC DC transmission technology which allows much higher voltages and transfer capacities. The experience record of CSC DC is also significantly larger.

Although it is expected that developments in VSC DC technology will increase its efficiency, operating voltages and transfer capacities over time it is likely that, for 2020, the majority of developments will largely involve currently available technology. Other related developments such as DC circuit breakers may make the interconnection of wind farms more attractive.

However, whether using AC or DC technology offshore, the operational safety of the grid will ultimately limit the capacity of the onshore offshore links to cover for generation shortfalls caused by faults in the links. This constraint corresponds to the maximum planned infeed loss risk of the grid and is currently about 1.3 GW in GB and 3 GW in continental Europe. Beyond those transfer levels, the provision of additional network redundancy and/or reserve will be required. These limitations also question the feasibility and attractiveness of "hubbing" or aggregating large offshore wind farms.

Standardisation of voltages and compatibility between manufacturers equipment would facilitate potential interconnections between wind farms.

3.2 The Investor versus the UK perspective

The CBA analysis has evaluated the benefits of JP development from a UK perspective, but these do not entirely coincide with the investor's perspective. In the UK, unlike the majority of Continental Europe, interconnector construction is undertaken by private companies whose investment decision will be based upon an assessment of the costs and revenues of the project. Interconnector revenues are directly linked to the projected flows on that interconnector. The arbitrage analysis above indicates potential interconnector utilisation of around 80% for Norway and Continental Europe and 85% for Ireland. So there is clearly scope for further interconnection and this has been shown by developer interest in interconnector construction.

Then the question becomes, how can interconnection be most cost effectively achieved for an investor?

For interconnection to Norway, an onshore to onshore direct connection offers the highest arbitrage potential at the lowest cost from the investor's perspective. From the UK's perspective the benefits are also positive, particularly in terms of carbon saved and security of supply. Interconnection via a wind farm at Dogger Bank is less attractive from an investor perspective, leading to higher project costs and lower arbitrage potential. While offering additional renewable generation, from a UK perspective interconnection via Dogger Bank is also less attractive due to lower carbon savings and security of supply benefits.

Interconnection between two relatively close wind farms appears a highly cost effective route, but will raise a plethora of contractual and regulatory issues. Furthermore interconnection is not the core business of wind generators and the realisation of an interconnection is conditional on the construction of the wind farms. There are also technical issues in terms of voltage standardisation and equipment compatibility between different manufactures. Such issues, although considered minor, are likely to complicate and raise project risks for an investor. In some cases however it may prove attractive to link wind farms, particularly those in close proximity using AC connections, for reliability reasons.

A relatively short direct onshore to onshore interconnection could be considered a low cost and low risk option from an investor's perspective. Furthermore, if combined with an onshore JP, then the option becomes increasingly attractive from both the UK and investor perspective.

A long subsea interconnection (such as Iceland) combined with a higher risk generation project must be considered a high cost, high risk project from an investor perspective.
So although from a UK perspective, the option may offer a positive CBA, when high investor risks and subsequent high project IRRs are taken into account, the option may be less attractive from an investor perspective.
To compensate the investor would seek greater revenue support, resulting in the project becoming less cost effective from the UK perspective.

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For enquiries please contact

Dr Florencio Castro-Sayas
T. +44 191 211 2405
E. fcastro@globalskm.com

Dr Lisa Woolhouse
T. +44 191 211 2403
E. lwoolhouse@globalskm.com

www.skmconsulting.com

Contact

TOM FOLEY T. +44 191 211 2400 E. tfoley@globalskm.com
13th Floor, Cale Cross House 156 Pilgrim Street Newcastle upon Tyne, NE1 6SU United Kingdom

PETER OLDROYD T. +60 3 6204 6604 E. poldroyd@skm.com.au
Suite E-15-01, Level 15 Block E, Plaza Mont' Kiara, 2 Jalan Kiara Mont' Kiara, 50480, Kuala Lumpur, Malaysia

BILL TOOHEY T. +61 3 9248 3135 E. btoohey@skm.com.au | 590 Orrong Road, Melbourne, Australia

BRIAN EAGERS T. +56 2 924 6423 E. beagers@globalskm.com | Monseñor Sótero Sanz 161, Providencia, Santiago de Chile

VINCE VELLA-BRINCAT T. +64 3 977 2939 E. vbrincat@skm.co.nz | Level 3, 321 Manchester Street, Christchurch, New Zealand

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