ENSGR 2009-026

ENSG 'Our Electricity Transmission Network: A Vision for 2020'

Full Report

A REPORT TO THE ELECTRICITY NETWORKS STRATEGY GROUP ON THE STRATEGIC REINFORCEMENTS REQUIRED TO FACILITATE CONNECTION OF THE GENERATION MIX TO THE GREAT BRITAIN TRANSMISSION NETWORKS BY 2020

Note: This report provides the full supporting data that was used to produce the ENSG summary report *'Our Electricity Transmission Network: A Vision for 2020'* (URN/09/752), which was published by DECC on 4th March 2009. No additional work beyond that summarised in the previously published document is included. It is published to provide further information on how the conclusions in the summary report were reached.

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Executive Summary

1.0 *Overview*

1.1 In July 2008, following the publication of the Government's consultation on a UK Renewable Energy Strategy, the Electricity Networks Strategy Group (ENSG), a cross industry group jointly chaired by the Department of Energy and Climate Change and Ofgem, requested the three GB Transmission licence holders, supported by an Industry Working Group (ENSG - Project Working Group (PWG)) to :

- Develop electricity generation and demand scenarios consistent with the EU target for 15% of the UK's energy to be produced from renewable sources by 2020; and
- Identify and evaluate a range of potential electricity transmission network solutions that would be required to accommodate these scenarios.

1.2 This report has been prepared by the PWG to discharge the actions placed on them by the ENSG. In taking the study forward, the working group was asked to identify potential technical, regulatory or commercial barriers to the delivery of the proposed reinforcements. This report examines the technical issues associated with network transmission reinforcements.

1.3 The reinforcements identified by this report are based on a range of scenarios that take into account the significant changes anticipated in the generation mix between now and 2020. In particular, the scenarios examine the potential transmission investments associated with the connection of large volumes of onshore and offshore wind generation that are required to meet the 2020 renewables target and new nuclear generation. The study concludes that, provided the identified reinforcements are taken forward in a timely manner and the planning consent process facilitates network development, then the reinforcements identified in this report can be delivered to the required timescales.

1.4 This report identifies and estimates the costs of the potential transmission reinforcements necessary to accommodate the connection of a range of new generation needed to meet the UK's renewable energy targets whilst, at the same time, facilitating the connection of other essential new generation that will be needed to maintain continued security of supply. To ensure that the identified reinforcements are sufficiently robust, they have been tested against a range of background scenarios, which take account of likely developments up to the year 2020. The total cost of the proposed reinforcements is £4.7bn and the resulting network can accommodate a further 45 GW of generation, of which 34 GW could be a combination of onshore and offshore wind generation. The opportunity has been taken to optimise the integration of onshore and offshore developments to facilitate a

significant saving, estimated to exceed £850M, in developing offshore networks, which may be achieved by making timely investment in the onshore network.

1.5 In identifying the potential transmission reinforcements, the opportunity was taken to, first, maximise the utilisation of the existing assets. Where the need for significant reinforcements has been identified, consideration has been given to employing the latest technology, especially where additional economic and/or additional environmental benefits can be expected. In such cases, due account has been taken of the lead time required to develop robust engineering solutions and the need to obtain the necessary planning consents for each reinforcement.

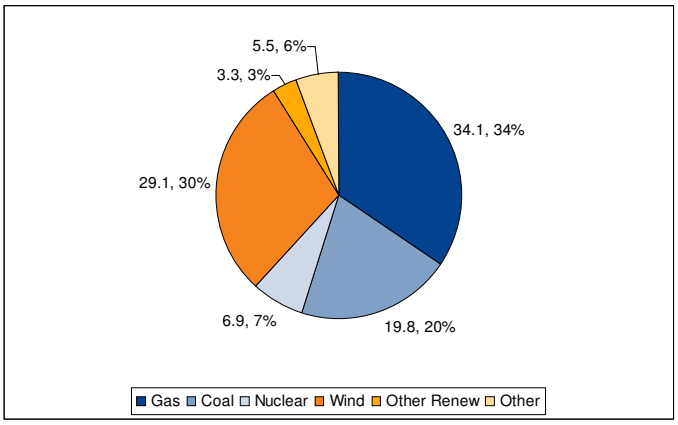
1.6 Whilst the potential reinforcements are categorised by the degree of confidence we have with regard to the need for proposed reinforcement, it is recognised that there is still a degree of uncertainty with regard to volume and timing of generation in any given area. It is therefore proposed to continue to monitor the developments of the market and update the scenarios accordingly. The proposed transmission reinforcement will be developed in such a manner as to ensure that the options are maintained at minimum cost, i.e undertaking pre construction engineering, and then taking beyond this stage when there is sufficient confidence that the proposed reinforcements will be required. This is the least regret solution, i.e it retains the ability to deliver to required timescales.

2.0 *Approach*

2.1 A number of electricity generation and demand backgrounds have been developed. In their development, numerous factors have been taken into account; particularly in relation to ensuring that the UK and Scottish Executive 2020 targets for renewable energy and the UK target for Greenhouse Gas emissions would be met. Such factors included the analysis of:

- closures of existing plants due to various legislation and age profile;
- contracted new connections for all types of plant;
- the potential for, and location of onshore and offshore wind generation; and
- the potential build rates for wind and new nuclear generating plant.

2.2 In developing a detailed background, issues such as: security of supply; the ability of the supply chain to deliver; and technological advances have been taken into consideration. The fuel mix in the scenario for 2020 (known as the Gone Green scenario), which was endorsed by the ENSG and on which the study is based, is set out below:



Fuel mix in 2020 of the 'Gone Green' Scenario
Generation connected to Transmission

2.3 The resulting generation background scenarios, upon which the studies are based, vary the capacity of renewable generation in Scotland from a minimum of 6.6 GW (this is the minimum required to meet the Scottish Executive target assuming that the existing hydro generation contributes to the target), a second scenario with 8 GW and a final scenario with a maximum of 11.4 GW by 2020. All scenarios considered achieve a total UK renewable energy contribution of 147 TWh by 2020, to achieve this, the volume of offshore wind farm generation in England and Wales was increased to compensate for any volumes less than 11.4 GW in Scotland. These scenarios will be referred to throughout this report.

2.4 The total offshore wind farm capacity in England and Wales is assumed to be in the region of 21 GW – 25 GW by 2020. In considering how this offshore capacity could be achieved, it is assumed that some 8 GW of Round 1 and 2 wind generation projects will proceed to completion, with the remainder being made up from the proposed Round 3 development sites. In determining the timing and location of the potential projects in England and Wales the report produced by Crown Estate (Round 3 Offshore Wind Farm Connection Study[1]) and the report recently published by DECC (National Grid input into DECC Offshore Energy Strategic Environmental Assessment[2]) were used as the basis of the future analysis, together with appropriate sensitivity studies.

2.5 The generation scenarios assume two new nuclear installations with a combined capacity of 3.3 GW by 2020. The existing signed agreements identified in the 2008 GB Seven Year Statement (SYS) and subsequent Quarterly Updates, were used as a basis for determining possible future nuclear sites.

[1] http://www.thecrownestate.co.uk/round3_connection_study.pdf
[2] http://www.offshore-sea.org.uk/site/scripts/consultation_download_info.php?downloadID=238

2.6 The developments in the generation market and the progress that Generators make in obtaining planning permission and the subsequent build rate will continued to be monitored and the 'Gone Green' scenario updated accordingly.

2.7 The generation assumptions made for the purpose of this report are entirely independent from and in no way pre-suppose the outcome of individual planning decisions about projects on particular sites and, in the case of nuclear, the Strategic Siting Assessment (SSA) process.

3.0 *Findings*

3.1 The predominant power flow on the GB transmission system is from the North towards the South. In the North of Scotland, local demand is, for the most part, adequately met by the portfolio of hydro generation, Peterhead power station and an increasing number of wind farm developments. Accordingly, there is a predominant net export of energy from the region to the Central Belt of Scotland. Additional power flows in the Central Belt of Scotland, within the Scottish Power Transmission (SPT) network, place a severe strain on the 275 kV elements of the network and, in particular, the north to south and east to west power corridors.

3.2 The circuits between Scotland and England are already operating at their maximum capability. Under all the generation scenarios considered, the transfers from Scotland to England increase significantly. Reinforcements identified to relieve the boundary restrictions across these circuits result in power transfers on the Upper North network of the England and Wales transmission system exceeding network capability. South of the Upper North boundary the increased power flows south from Scotland and North West of England progressively diminish as they are offset by the closure and displacement of existing conventional generation along the way. Accordingly, while there are transmission overloads in northern England the effects are greatly muted as the flows travel towards the Midlands.

3.3 Offshore wind generation in England and Wales, together with the potential connection of new nuclear power stations raises a number of regional connection issues; particularly in Wales (North & Central), and the South West and along the English East Coast between the Humber and East Anglia. The increased power transfers across the North to the Midlands boundary and/or the increased generation off the East Coast and/or Thames Estuary result in severe overloading of the northern transmission circuits securing London.

4.0 *Analysis to determine transmission reinforcement requirements.*

4.1 The range of potential power flows on the GB transmission system has been determined on the basis of the currently authorised GB transmission system (i.e. the existing GB transmission system together with all the approved transmission system reinforcements assumed to be in place for the years 2015 and 2020). Such authorised transmission reinforcements include:

- the proposed Beauly – Denny 400 kV line,
- the uprating of the transmission capacity between Scotland & England (TIRG); and,
- the additional transmission capacity around the North West and North East of England.

4.2 Application of the current GB Security and Quality of Supply Standard (GB SQSS) was used in determining the reinforcements necessary under the 'Gone Green' generation scenarios. In determining wider infrastructure requirements we have assumed a high level of network sharing. By applying the GB SQSS against the agreed 'Gone Green' scenarios and appropriate sensitivity studies, a range of potential power transfers can be determined at winter peak. These transfers are not necessarily the maximum transfers and may be significantly higher at off-peak times; particularly in areas where there are significant volumes of wind generation. The impact of our sharing assumptions and the potential for increased transfers is considered in more detail in the Cost Benefit Analysis (CBA) described below.

4.3 When considering local generation connections, in areas which predominantly contain wind and/or nuclear generation, given the high value associated with low carbon generation, developing a transmission network is generally more economic and efficient than curtailing low carbon production. If the local network was designed to accommodate only 90% of the output of a wind farm generator, the cost of constraints would be in the region £5-7M per annum per GW of installed wind generation. This level of constraint cost is generally higher than the marginal cost of providing transmission capacity, nevertheless, the opportunity will taken to optimise the level of renewable generation which can be accommodated to ensure economic and efficient level of investment into transmission is undertaken.

4.4 Even with a high level of assumed sharing, there is concern that due to the relatively low utilisation of renewable intermittent generation together with the increased margin between installed generation capacity and demand, there may be greater sharing of existing transmission capacity. A Fundamental Review of the GB SQSS and a Transmission Access Review (TAR) are currently being conducted. Whilst this report did not undertake analysis against all variants under consideration by these two reviews, a CBA was undertaken in respect of proposals to reinforce major system boundaries. The

level of transmission capacity identified by the CBA should be consistent with the conclusion of both the review of the GB SQSS and the TAR, since it ensures that the GB transmission system is designed to give the most economic and efficient solution. Nevertheless, the proposals presented within this report will be subject to further examination in light of the conclusions of the two reviews. These reviews are due to be completed this year, and this re-examination will not impact on delivery of required network capacity.

4.5 The CBA has been fully developed for all reinforcements from the central zone of the Scottish Hydro Electric Transmission Ltd (SHETL) system through the SP Transmission (SPT) system to the North of England. In undertaking a CBA the generation has been ranked as described in Annex A of this report. That is, generation has been grouped according to fuel type (e.g. nuclear, wind, large coal, modern gas etc.) and ranked in accordance with perceived likelihood of operation based on historic information covering the last few years. The generation constraint prices (i.e. bid on/off) are based on the average price seen over the last few years. Data in respect of the current year are atypical and are influenced by unusual conditions that are not believed to be representative of the long-term outlook, which would result in higher constraint cost if utilised in future constraint analysis over a long period. The cost of carbon is assumed to be included within the energy cost used in the study. Whilst this assumption is unlikely to have a material impact on the future constraint cost, it is recognised that it is likely to lead to an underestimation of the cost of losses in future years and, as a consequence, underestimate benefits of future transmission upgrades, but these underestimations are not considered to be material.

4.6 A generic wind output distribution curve has been developed which reflects the intermittent nature of wind generation output. The model ensures that the different generation output over seasons is calculated (average utilisation of 38% and 30% respectively for winter and summer has been used) along with an appropriate diversity factor for wind farm generation across the GB system. The wind generation output at any given time is determined by Monte Carlo sampling. The CBA model then seeks to dispatch the most economic generation, whilst not violating transmission capacity limits. A series of sensitivity studies have then been undertaken to ensure that proposals arising are robust against a wide range of sensitivities which are discussed in the main report.

4.7 When identifying a shortfall in network capacity, consideration has been given to traditional solutions such as reconductoring circuits, upgrading to a higher voltage and constructing new lines. However, it is recognised that traditional methods of enhancing system capacity, particularly those that involve new overhead line routes, are difficult to achieve due to planning constraints and environmental concerns. Such difficulties can result in long delays in providing the required transmission capacity and consequential delays in

facilitating the connection of sufficient volumes of renewable and other forms of generation needed to meet UK targets. As a result, the Transmission Licensees have investigated the potential for new or previously unused technologies on the GB transmission system in order to either: enhance and maximise the use of existing assets; or to provide new infrastructure with minimal environmental impact and an acceptable level of technological risk. Discussions have been taking place with equipment manufacturers regarding the use of series compensation, High Voltage Direct Current (HVDC) technologies and developments in sub-sea cables.

5.0 *Proposed Reinforcements*

5.1 *Within the North Scotland (Scottish Hydro Electric Transmission Licence area).*

5.1.1 The proposed Beauly-Denny rebuild is an important step in developing a transmission system in the North of Scotland of sufficient capacity to accommodate renewable development proposals. With this upgrade in place, further reinforcement of the North of Scotland transmission system can be achieved by the strengthening of other elements of the existing system.

5.1.2 Further improvements to the mainland system are required to make maximum use of the existing infrastructure and overhead line routes to connect renewable generation developments on the Scottish mainland and the islands. This can be achieved by reconductoring and re-insulation work on existing tower routes, along with development of new substations or extensions to existing substations.

5.1.3 The first stage of upgrades will be required to reinforce North-West Scotland and transfer capability south to the Central Belt. This first phase consists of the Dounreay – Beauly – Kintore (DBK) 275 kV upgrade, which together with the east coast reconductoring and re-insulation works included in 5.2.1 below provide a transmission system in SHETL's North of Scotland area capable of accommodating 5.5 GW of renewables (which is consistent with the 8 GW scenario). The total cost of the DBK reinforcement is £180M, and that of the East Coast work is £150M.

5.1.4 A second phase of upgrades would be required to accommodate 6.9 GW of renewables in the North of Scotland, contributing to the total figure of 11.4 GW for Scotland. These upgrades comprise an additional £450M reinforcement between Caithness & Moray, together with the Eastern HVDC Link described below in 5.2.3. The requirement for these upgrades would be assessed as generation develops, but pre-construction work should commence at the earliest opportunity.

5.1.5 The provision of connection capacity to the Scottish Islands via subsea links to the main interconnected system, together with the subsea link between the Kintyre peninsula and Hunterston, allows the connection and contribution of 1.5 GW-2 GW of renewable generation from these areas.

5.2 *In respect of upgrading the main interconnected Scottish system from the North of Scotland to the Central Belt, and on to the North of England there are three main elements.*

5.2.1 The 'Incremental' upgrade, which includes reconductoring and re-insulation work on existing tower routes, along with the development of new and existing substations and the installation of series compensation thus making maximum use of existing transmission routes. The total cost of the reinforcements identified below is some £625M:-

- SHETL East Coast reconductoring, re-insulation and substation works - £150M
- SPT East Coast reconductoring, re-insulation and substation works - £135M
- SPT East West Upgrades -£80M
- SPT/NGET Series compensation on the circuits connecting the Scottish and English Networks - £160M
- NGET Reconductor Harker – Quernmore- £100M

5.2.2 The Western subsea HVDC Link, a 1.8 GW HVDC link between Hunterston and Deeside. This provides additional capacity across the 'interconnector' circuits and additional capacity across the upper North of England. The total cost of the reinforcement is £760M and the major elements of the reinforcements are summarised below:

- SPT - Western HVDC Link and associated works - £400M
- NGET – Substation Works at Deeside and HVDC Link - £360M

5.2.3 The Eastern subsea HVDC Link, a 1.8 GW HVDC between Peterhead and Hawthorne Pit. This provides additional capacity across the key transmission boundaries between central Scotland and the north of England and limited additional capacity across the upper North of England. The total cost of the reinforcements is £700M and the major elements of the reinforcements are summarised below:

- SHETL onshore substation works & Eastern HVDC Link - £340M
- NGET onshore substation works & Eastern HVDC Link - £360M

5.2.4 Whilst all three reinforcements identified above are required by 2020 in the 11.4 GW scenario (based on the deterministic requirements of the GB SQSS and supported by the CBA), only two of the reinforcements would be required to meet the 8 GW scenario in Scotland. In determining which of the two reinforcements should be taken forward first, the CBA did not demonstrate conclusively that any particular two reinforcements offered significant benefit over any other combination against the scenarios under consideration. When considering the generation sensitivities, particularly extending the life of the Hartlepool and Heysham 1 Nuclear power stations (scenario assumes they close around 2017/18), then the western HVDC link reinforcement, along with the 'Incremental' provides the most robust solution.

5.2.5 If the Scottish renewable generation contribution is limited to the 6.6 GW of wind generation in total (i.e the minimum required to meet the Scottish Executive target if hydro is assumed to contribute), then any single reinforcement identified above provides sufficient transmission capacity.

5.2.6 A high level analysis has indicated that there is a high probability that at least 8 GW of wind generation will connect in Scotland. It is therefore proposed to proceed with the Western HVDC Link and the incremental upgrade immediately, with a target completion date of 2015 at a cost of £1,385M, but develop the incremental reinforcement in such a manner as to install a subset if necessary, and then proceed with the Eastern HVDC link with a target completion date of 2018 at a cost of £700M. Whilst the Eastern HVDC link is not required until 2018 it will be necessary to undertake some preliminary engineering to ensure it can be integrated into the network.

5.3 *North Wales – Stage 1*

5.3.1 The scenarios assume that up to 4 GW of offshore wind in the Southern Irish Sea may connect since the offshore generation in this area is expected to be among the least cost of the Round 3 sites. Round 3 wind farms in the area will seek to utilise the same capacity as the existing pumped storage plant, Round 2 developments, possible interconnections to Ireland and new nuclear replanting at Wylfa. When total generation, whether wind or nuclear generation, on Wylfa exceeds 1.8 GW[3] it will be necessary to construct a new circuit from Wylfa through to Pentir and establish the second circuit between Pentir and Trawsfyndd, together with some associated works further east. These works need to be undertaken in sequence and, in order to provide

[3] GB SQSS Review Group, Review Request GSR007, 'Review of Infeed Loss Limits' refers. GSR007 is considering raising the threshold limits of the normal (currently 1,000MW) and infrequent (currently 1,320MW) in recognition of the likelihood that single units in excess of 1,320MW (possibly posing a loss of power infeed risk of up to 1,800MW) will connect to the GB transmission system.

additional capacity by 2015, the engineering of some elements needs to commence early in 2009 if the timeline is to be retained.

5.3.2 To provide offshore networks developers with sufficient confidence that they can connect to Wylfa, it may be necessary to seek consents for the new line prior to the development of the offshore networks. Commitment to full construction can then be adjusted as the build up of generation materialises. This approach can achieve a potential saving of offshore network cost in the region of £500M by facilitating connections at Wylfa rather than a more remote site

5.3.3 The proposed reinforcements will cost £400M, for completion by 2017.

5.4 *Central Wales- Stage 1*

5.4.1 The Welsh Assembly Government Technical Advice Note 8 identifies an onshore wind generation target of 800 MW. The majority of wind resource is in central Wales, which has no immediate connection to the main interconnected transmission system.

5.4.2 New transmission assets including overhead line and cable sections need to be commissioned in order to connect the new generation to the transmission network. As the generation is made up of a number of small to medium wind farms, the current proposal is to create a hub substation to which all wind farms connect. A single transmission route will then be used to connect to the transmission network in the Legacy-Shrewsbury-Ironbridge circuits. Exact locations of both substation and transmission connection point are being evaluated.

5.4.3 The cost of these works above is estimated to be £225M, for completion by 2015.

5.5 *Combining North & Central Wales – Stage 2*

5.5.1 The potential for further generation in Central Wales and significant new generation in the North Wales (combination of wind generation and nuclear on Wylfa) with the resulting pressure the North Wales boundary has highlighted an opportunity for considering an additional development in Central Wales. The capacity of the connection to the main interconnected system will frequently be under-utilised due to the typical load factor for wind generation. An additional connection from the Trawsfynydd area to the new substation in Central Wales would allow full utilisation of this circuit and provide additional capacity across the North Wales boundary. Furthermore, by connecting further south than the Legacy-Shrewsbury-Ironbridge circuit, for example, Ironbridge or Bishop's Wood substations, additional relief on heavily loaded circuits

will be realised. Exploration of the transmission technology used is critical to making full use of this new through route. The report on the findings of the final stage of the project that examined network requirements for the period 2020 to 2030 (to assess any potential implications fro the 2020 conclusions) is set out in an addendum to this report.

5.6 *English East Coast Reinforcement, Humber – Stage 1*

5.6.1 Previously published investigations such as The Crown Estate 'Round 3 Offshore Wind Connection Study' and National Grid's input to the DECC Offshore Energy Strategic Environmental Assessment have considered a total of up to 12 GW of Round 3 offshore wind generation from the Dogger Bank and Hornsea areas connecting into the onshore transmission network in the Humber area. However, scenarios utilised in this study assume a maximum of between 4 and 8 GW by 2020 (dependent on the level of onshore wind assumed to arise in Scotland). The conclusions from this study propose to optimise both onshore and offshore transmission networks by integrating the design of these networks in order to capture significant cost savings (potentially in the range £200-300M). This can be achieved by connecting some of the Round 3 wind farms in this region via direct tee connections into an onshore HVDC link connecting the Humber area to East Anglia.

5.6.2 Connecting these two areas affords the extra benefits of providing additional capacity for new generation connections to the north of the North to Midlands boundary as well as delaying, but not removing, the need for reinforcement in the East Anglia region. This comes as a result of the increased functionality and controllability of HVDC circuits relative to standard AC overhead lines.

5.6.3 In view of the novel nature of this development, pre-engineering works will be required to ensure that the proposed solution can be developed to required timescales. Otherwise, it may be necessary to develop an alternative solution involving new 400 kV overhead lines, thus negating the potential savings.

5.6.4 The cost of the onshore works is estimated to be £510M, for completion by 2017.

5.7 *English East Coast Reinforcement, East Anglia Stage 1*

5.7.1 It is anticipated that between 3 and 4 GW of Round 3 offshore wind generation will be developed in waters directly east of East Anglia. The nearest onshore substations for connection are either Norwich Main or Sizewell, which are both located on the same 400 kV route. Therefore

Round 3 offshore wind projects will interact significantly with the potential for nuclear replanting at Sizewell (of up to an additional 3.3 GW) on this part of the network. Reinforcement of the network is required for either offshore wind generation and/or nuclear replanting at Sizewell.

5.7.2 The reinforcements proposed for this area of the network include reconductoring the double circuit route from Walpole to Norwich through Bramford, a new 400 kV substation at Bramford with all circuits from Norwich Main, Sizewell, Pelham and Rayleigh turned in and a new section of 400 kV double circuit overhead line, approximately 27 km in length from Bramford to the existing tee point down to Rayleigh (near Twinstead), this would then create two double circuit routes to the west out of Bramford.

5.7.3 The cost of onshore works is estimated to be £400M, for completion in 2017.

5.8 *English East Coast Reinforcements – Humber & East Anglia Stage 2*

5.8.1 Should the volumes of offshore wind generation surpass the expected volumes of between 4 and 8 GW after 2020, new connections between Walpole and the Cottam – Eaton Socon line and/or Grimsby West and Keadby may be required, this will be considered further in the next stage of the project.

5.9 *London – Stage 1*

5.9.1 Historically, the network in and around London was developed to secure demand in the capital and its surroundings, when the major generation sources were the oil and coal fired plant in the Thames Estuary, or the coal-fired plant in the East and West Midlands. Additionally, it handled transfers to and from the interconnector at Sellindge.

5.9.2 However, several factors associated with the scenarios and sensitivities investigated, including the introduction of new low-carbon generation and liberalisation of European energy markets, drive a need for additional transmission capacity in the London area. Specifically, increased generation in East Anglia and the Thames Estuary, potential increase in interconnection with mainland Europe and the potential for future demand increases associated with the electrification of transport and/or the decarbonisation of space heat. As a consequence there will be a need for additional transmission feeding central London from the north-east, and ultimately a need to reinforce east-west ties.

5.9.3 The proposed reinforcement is to uprate a 275 kV overhead line from Waltham Cross to Hackney via Brimsdown and Tottenham to 400 kV.

The cost of these works is estimated to be £190M, with a completion date of 2015.

5.10 *London - Stage 2*

5.10.1 In the longer term, a section of the 'middle' 275 kV ring between Tilbury, Warley, Waltham Cross and Elstree may need to be uprated to 400 kV to provide additional capacity between the Estuary and North London. The cost of this additional work is estimated at £85M, with a notional completion date of 2022, subject to a future evaluation of need based on developments at that time.

5.11 *South West*

5.11.1 This area of the network, around the Severn Estuary, is characterised by large volumes of localised generation, high demand levels and a limited export capacity. Future changes in the generation connected in this region, including the potential for large amounts of gas fired generation and possible nuclear replanting at Hinkley Point and/or Oldbury-on-Severn, drive the need for additional transmission capacity. Planned offshore wind generation through future rounds of wind leasing in this area further add to this requirement.

5.11.2 Proposed reinforcements to accommodate the agreed 2020 scenario and sensitivities investigated include a new 400 kV circuit between Hinkley Point and Seabank of approximately 50 km in length. Reconductoring of existing circuits between Hinkley Point, Melksham and Bramley is also needed to provide the power generated in this area with a stronger electrical connection to the demand centre of London.

5.11.3 The cost of these works above is estimated to be £340M, with a completion date of 2017.

6.0 *Transmission National Planning Framework (NPF) and National Policy Statements (NPS)*

6.1 The Transmission reinforcement proposals are consistent with requirements to meet the UK Targets and in order to meet these challenging programmes of delivery dates it is essential that there are no significant delays in obtaining the necessary planning permissions. As part of the pre-construction engineering, it is proposed that planning applications will be taken forward ahead of commitment from any individual generator.

6.2 The high level diagram of the proposed reinforcements for Scotland is shown in Figure 1 (page 19). The Scottish Executive's National Planning Framework

for Scotland already includes the onshore upgrades and the island links and supports proposals for transmission upgrades.

6.3 Figure 2 (page 20) shows, at high level, the proposed reinforcements for England & Wales, and it is anticipated that the need for such reinforcements will be discussed in the proposed National Policy Statement for Electricity Networks Infrastructure.

7.0 *Capex requirement*

7.1 The estimated capex requirement to deliver the reinforcements identified above, the amount of generation which can be accommodated and the potential reduction in cost of delivering offshore networks is shown in the table below. The estimated capex requirement to deliver the reinforcements will be subject to a rigorous review as part of the pre-construction engineering stage.

Region	Reinforcement	Cost (£M)	Capacity of generation which can be accommodated (GW)			Potential saving in offshore network costs (£M)	Net costs (£M)
			Wind	Nuclear	Total		
Scotland – Stage 1, 2015	North of Scotland Upgrade Incremental Scottish Upgrade Western HVDC Link -	180 625 760	8	0	8	NA	1565
Scotland – Stage 2, 2018	North of Scotland Upgrade Eastern HVDC Link -	450 700	4	0	4	NA	1150
Wales – Stage 1	North Wales - 2017 Central Wales - 2015	350 225	4 – 6	0 – 3.3	4 – 9.3	500	75
English East Coast – Stage 1	Humberside East Anglia	510 400	7 – 11	0 – 3.3	7 – 14.2	350	560
London	London	190	1 – 2	-	1 – 2	-	190
South West	South West	340	2 – 3	3.3 – 3.3	5. 3 – 6.3	-	340
Total		4730	26 – 34	3.3 – 9.9	29.3 – 43.9	850	3880

7.2 The above costs are for the upgrades to the main interconnected system and exclude the provision of subsea links to the Scottish Islands and offshore network costs for offshore wind. The offshore network costs will be of the order of £400/KW, as indicated in the Crown Estate report on offshore connection costs.

7.3 Timely investment in the onshore network can provide significant benefits in facilitating the connection of offshore networks with a potential saving of £850M. However, it should be noted that many of the proposals involve the use of new and novel solutions and the integration of these solutions into the

existing transmission system needs to be carefully engineered. If the transmission network is to facilitate the connection of renewable generation in a timely manner it is essential that pre-construction work commence immediately. Recognising the use of new technology, it is difficult to determine the total cost of pre-construction engineering costs, but for schemes of this complexity it would be normal to anticipate costs in the range of 2-5% of total scheme costs, with typically 0.25-0.5% of cost occurring in year 1. For the package of schemes identified above, it is estimated that the pre-construction cost will be in the order of £150M with a cost of some £10M to £20M occurring in the first year.

8.0 *Taking the Investment Proposals Forward*

8.1 The transmission reinforcements identified above are required to accommodate the generation identified in the scenarios and sensitivities studies considered. Like all forecasts, there is a degree of uncertainty with regard to the final outcome. In developing proposals to meet the 2020 targets there will be a varying degree of confidence of the certainty of future requirements. By undertaking the pre-construction engineering of the schemes identified in this report, it ensures that the proposed reinforcements can be engineered satisfactorily, and the lead times to deliver are maintained. This is the least regret solution, i.e, it retains the ability to deliver to required timescales.

8.2 In considering the schemes identified above, there is a very strong need case for the following reinforcements which are considered most likely to be required:

- Dounreay – Beauly – Kintore 275 kV upgrades;
- Incremental Scottish Upgrade
    - SHETL/SPT East Coast Upgrades
    - SPT East – West Upgrading
    - SPT/NGET – Series compensation
    - NGET Reconductoring Harker – Quernmore;
- Western HVDC Links;
- North Wales Reinforcement;
- Central Wales;
- English East Coast - East Anglia;
- London.

8.3 While the following also have a strong need case, there remains some uncertainty with respect to their required completion dates:

- Caithness to Moray Reinforcement;
- Eastern HVDC Link;
- English East Coast – Humberside (HVDC link);

- South West.

8.4 If the transmission network is to be developed in a timely manner to facilitate UK Government & Scottish Executive targets, pre-construction engineering should commence immediately for all the schemes identified above. Whilst there is presently a very strong need case to progress, a full review will be undertaken on completion of pre-construction engineering to confirm required completion dates. A high level timeline has been established for the proposed reinforcements, this indicates key milestones including a view of a planning consent timeline. This timeline will be further developed during the pre-construction engineering phase.

8.5 A number of other reinforcements have been identified in the report, but at this stage there is insufficient confidence to proceed with pre-construction engineering.

Figure 1

Stage 1 and 2 transmission reinforcements for Scotland

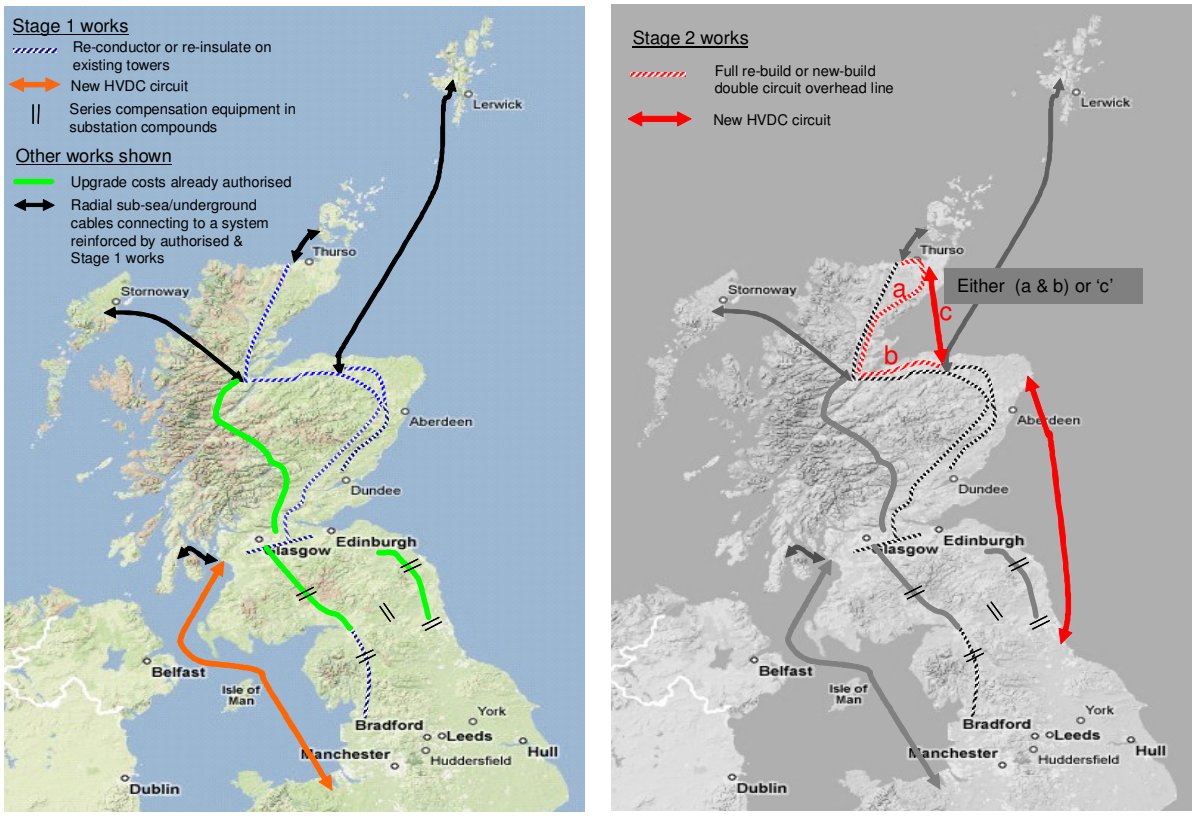
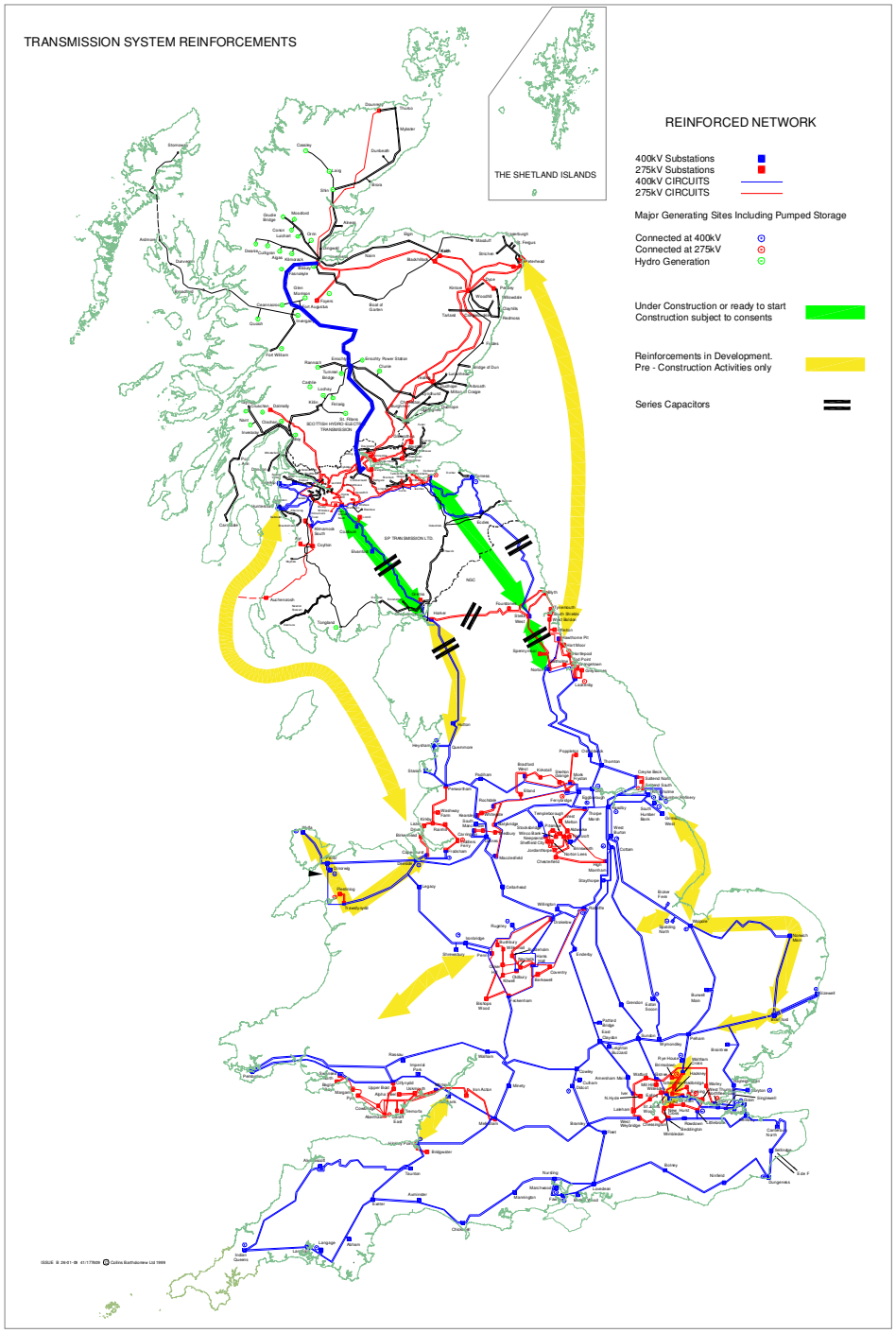


Figure 2: Proposed reinforcements for England and Wales



Chapter 1 - Introduction

1. Under the EU's proposed renewable energy targets for member states, the UK's contribution is for 15% of the UK's energy (electricity, heat and transport) to come from renewable sources by 2020. The reformed Electricity Networks Strategy Group (ENSG) has agreed to consider the impact on the GB Transmission Networks if the renewable energy target for the UK were to be met predominantly by means of electricity generation. The ENSG has requested the three GB Transmission Licensees to:

   - for the years 2015 and 2020, develop generation and demand scenarios based on available interpretations of the 15% UK renewable energy target that would be consistent with that target. Those scenarios to also reflect any views of bodies in Scotland, England and Wales responsible for the consenting of generation, regarding maximum generation capabilities in given regions. Define meaningful sensitivities to give ranges of required transfers across key boundaries.

   - quantify the level of renewable generation that could be accommodated on the existing transmission system in 2015 based only on onshore transmission upgrades with low associated consent and technology risk.

   - identify and evaluate a range of potential network solutions for 2020 including both onshore and offshore reinforcements that would accommodate generation and demand scenarios consistent with the 15% UK renewable energy target in 2020.

2. In addition, this report identifies the transmission reinforcements that would accommodate a range of new generation plant types and are robust when tested against a range of background scenarios.

3. The generation scenarios for 2015 and 2020 have taken account of expected changes to the plant mix.

4. The composition of plant types assumed by 2020 to replace the plant that has closed and also to reflect the intermittency of wind generation is shown below.

   Plant closures

   - 12 GW Coal and Oil LCPD;
   - 7.5 GW Nuclear;
   - Some gas and additional coal.

   Significant new renewable

   - 32 GW wind (21 GW offshore & 11 GW onshore);

- Some tidal, wave, biomass & solar PV.

Significant new non renewable build

- 3 GW of new nuclear;
- 3 GW of new supercritical coal (some with CCS);
- 11 GW of new gas.

5. The base generation scenario, scenario 1, has been subject to a rigorous process of challenge and review to assess its plausibility, and we are satisfied that the scenario it describes is capable of being delivered although it is extremely challenging. The generation mix has been validated against a range of consultants' reports some of which formed the basis of the generation mix published in the Government's Renewable Energy Strategy (RES) consultation document in June 2008. An overview of the scenarios used is set out below in table 1.1

Table 1.1: Scenario overview

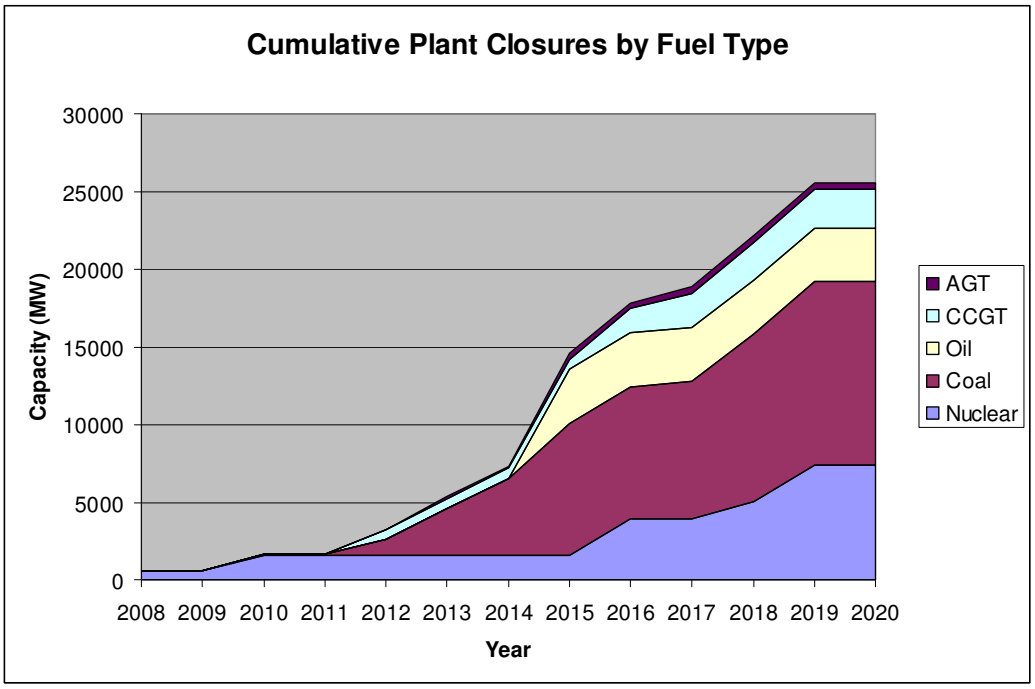
Electricity		Scenario 1[1,2]	Scenario 2[2]	Scenario 3[2]
Wind Capacity	(GW)	20.9 E & W 11.4 Scotland[3,4]	24.3 E & W 8.0 Scotland[4]	25.7 E & W 6.6 Scotland[4]
	(TWh)	98	98	98
Other Renewable (TWh)		49	49	49
Total Renewable (TWh)		147	147	147
Renewable % of total		36	36	36

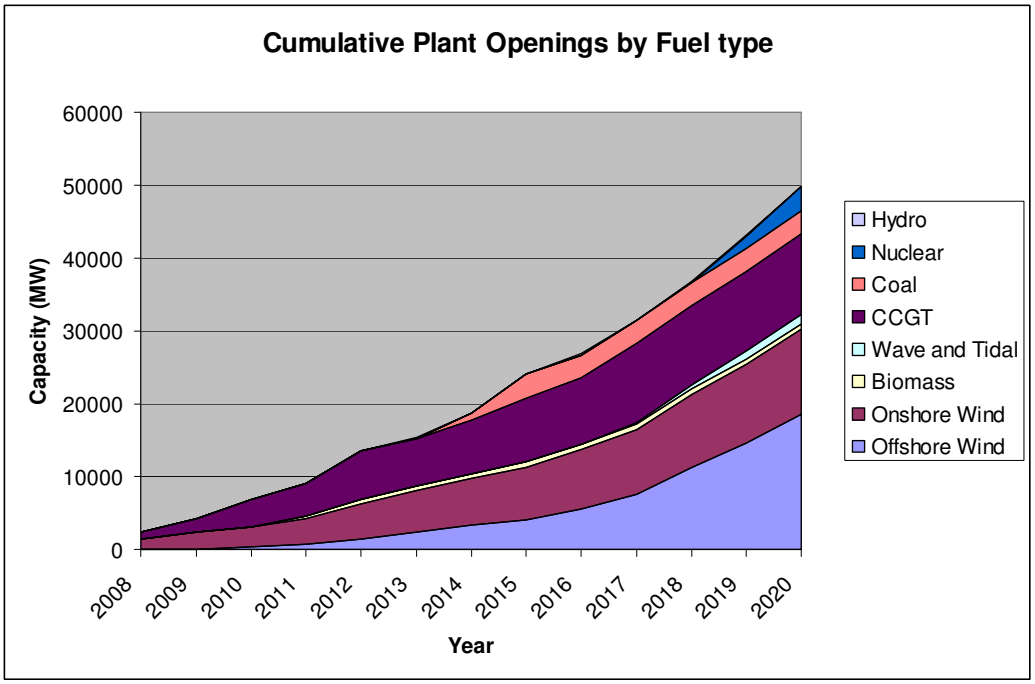
Note 1 This scenario provides a optimum UK solution, but it does requires a greater volume of renewable generation in Scotland than the present Scottish Executive targets.
Note 2 For all scenarios, there have been a range of sensitivity studies undertaken with respect to spatial location of Wind, Nuclear and other generation technologies – these are discussed in more detail in regional assessment of transmission capacity. Peak demand level is 60 GW.
Note 3 10.7 GW onshore, 700 MW offshore
Note 4 In addition to the wind capacity there is 1.4 GW of existing hydro capacity in Scotland

6. The phasing of plant closures and openings for scenario 1 are shown in the charts below. Sensitivity to location of openings and timings of openings and closures has been investigated in the study analysis.

7. The overall total of renewable energy generated in all the detailed scenarios remains constant. The difference between the scenarios is the respective penetration in England & Wales and Scotland. The spatial disposition of the generation will be discussed in a later chapter.

8. The power system analysis undertaken is split into two broad categories; connections local to generators and the main interconnected transmission system. The outage and fault events that require investment to secure against are detailed in the GB SQSS (Security and Quality of Supply Standards) as are the transmission system operating parameters that need to be controlled, for example generator stability and system voltage.





9. The principal difference in analysing local connections and the main interconnected transmission system is the treatment of generator capacity. For local generation connections the transmission circuits must be capable of carrying the full output of all generators served by them,

whereas when analysing the main interconnected transmission system, that is parts of the transmission network that supply more than 1500 MW of demand, at peak demand all conventional generation is scaled to a percentage of full output that is dependant on the plant margin used in the study. Furthermore, intermittent generation such as wind is scaled an additional amount based on anticipated load factors. A more detailed discussion of the above can be found in Chapter 3 of this report.

10. When a shortfall in local connection or main interconnected transmission system capacity is identified, dependent upon the nature of the shortfall, solutions that relieve the identified problem(s) will be developed. The first and overriding principle in developing the network is to maximise the use of existing assets, for example using a new conductor on an existing overhead line route. All solutions developed will then be tested against various background sensitivities, with the most appropriate overall reinforcement taken forward as a network investment. In this study a major consideration for each development is its impact upon other parts of the transmission network; this being particularly important due to the significant changes from the current position. Therefore the reinforcements proposed provide an overall solution that delivers the most economic, efficient and coordinated system within the overall time delivery constraint.

11. The consideration of appropriate reinforcements has not been restricted to plant and technologies currently in use on the GB network. Instead, where significant economic and environmental benefits can be demonstrated, and where there is sufficient time to develop robust engineering solutions, new technologies and existing technologies not previously connected to the GB network have been employed.

12. Due to wind resource availability, by 2020, offshore renewable generation will form a significant proportion of the renewable generation plant in England and Wales. The development of offshore and onshore networks independently of each other is unlikely to produce the lowest overall cost solution. As such, and where appropriate, this report seeks to integrate offshore and onshore networks to ensure that the most economic and efficient solutions are developed.

13. The generation scenario has assumed two new nuclear power stations by 2020 with a combined capacity of 3.3 GW and a further three installations by 2030. The Government noted in the Nuclear White Paper that it expected that nominations to build new nuclear power stations would focus on areas in the vicinity of existing nuclear facilities. This reflected an indication from industry that these are the most suitable sites. The Government will undertake a Strategic Siting Assessment (SSA) in 2009, to assess nominated potential locations for their suitability for the deployment of new nuclear power stations by 2025. This exercise is being accompanied by the Strategic Environmental Assessment (SEA). This report acknowledges that the new nuclear power stations would site at or near to existing facilities and the analysis takes into

account the uncertainty of the order in which they are to be developed. Current connection contractual position and closure estimates are detailed in Chapter 3 of this report.

14. All studies and economic evaluations have been undertaken in accordance with the existing GB SQSS and transmission access arrangements (TAR). The authors are aware that both the GB SQSS and TAR are currently subject to review. However, the authors are closely involved with developments in both frameworks and believe that the proposed changes to the documents will not impact on the need for the reinforcements proposed, but may require minor modifications which can be addressed in the design phase of the delivery programme.

15. An addendum to this report looks beyond 2020 to 2030 to verify an ongoing requirement for the 2020 system.

Chapter 2 - Scenario Development

Overview:

16. The generation background and demand forecast utilised in the Transmission Investment Options Study have been developed to enable the UK to meet its renewable target for 2020, i.e. 15% of all energy to come from renewable sources. To achieve this target significant contribution is needed from the electricity, heat and transport sectors, as well as advances in energy efficiency. This scenario has been called 'Gone Green'.

17. An energy model has been developed that enables analysis of how each of these sectors may be able to contribute to the renewable target. In so doing consideration has been given to issues such as security of supply, the ability of the supply chain to deliver, technological advances and grid connection issues. The detailed input data, assumptions and output from the model have all been subject to a rigorous process of challenge and review to assess their plausibility. While it is an extremely challenging target it is believed that the scenario described and summarised below is capable of being delivered.

2020 Scenario - Gone Green

Plant closures

- 12GW Coal & oil LCPD
- 7.5GW nuclear
- Some gas & additional coal

Plausible but Extremely Challenging

Significant new renewable

- 32 GW wind (21GW offshore & 11GW onshore)
- Some tidal, wave, biomass & solar PV

Significant new non renewable build

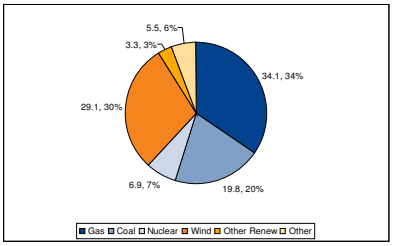
- 3GW of new nuclear
- 3GW of new supercritical coal (some with CCS)
- 11GW of new gas

Renewable share of generation grows from 5% to 36%

Electricity demand remains flat

- Reductions from energy efficiency measures
- Increases from heat pumps & cars

Contribution also required from heat & transport



2020 Target Description	Progress
UK Renewable Energy Target 15% of final energy demand	✓
2050 CO_2 Target on correct 'flight path'	✓
Scottish Renewables Target	✓

Summary

Generation gap caused by closures is filled with wind, augmented by gas & clean coal. Nuclear returns in 2020.

18. The generation mix has been validated against a range of consultants' reports, some of which formed the basis behind the generation mix

published in the Government's Renewable Energy Strategy (RES) consultation document in June 2008. This validation is shown in Table 2.1 for 2020 and compares National Grid's Business As Usual (BAU) case and Gone Green scenario with Redpoint's[4] three scenarios and SKM's four scenarios[5].

Table 2.1: Comparison of Total Capacity

	National Grid		Redpoint			SKM			
2020 GW	**BAU**	**Gone Green**	**Status Quo**	**RO32noSB**	**RO37SB**	**BAU**	**Lower**	**Middle**	**Higher**
Coal	**23.1**	**19.8**	**23.7**	**15.0**	**16.5**	**23.3**	**21.5**	**21.4**	**20.1**
Gas	**39.1**	**34.1**	**41.0**	**41.3**	**38.9**	**32.4**	**27.9**	**26.4**	**25.9**
Nuclear	**6.9**	**6.9**	**3.7**	**3.7**	**3.7**	**6.0**	**6.0**	**6.0**	**6.0**
Wind	**15.8**	**32.3**	**12.2**	**28.1**	**28.1**	**4.7**	**32.9**	**38.5**	**48.4**
Other Renewables	**4.3**	**8.0**	**4.1**	**8.0**	**8.2**	**2.4**	**4.4**	**5.2**	**5.6**
Other	**3.8**	**3.8**	**3.5**	**3.5**	**3.5**	**5.8**	**5.8**	**5.8**	**5.8**
Total	**93.0**	**104.9**	**88.2**	**99.6**	**98.9**	**74.6**	**98.5**	**103.3**	**111.8**
Demand TWh	**373**	**365**	**372**	**360**	**360**	**n/a**	**n/a**	**n/a**	**n/a**
of which embedded	5.6	8.0	n/a	n/a	n/a	6.9	7.9	9.7	11.2

Capacity excludes Interconnectors, NI & microgen
TWh includes imports

19. The figures are for total generation in Great Britain covering both transmission and distribution (embedded) connected generators. The Gone Green capacities compare well against the consultants' scenarios and fall within the range of potential outcomes, e.g. wind at 32 GW compared to a range of 28-48 GW for non BAU scenarios.

20. The results of this work for the electricity sector are summarised in Table 2.2 below and compare the renewable generation output to the view contained within the RES document. The results show a slightly higher contribution from renewable electricity generation when compared with the RES document. The ENSG Project Working Group has agreed the detail behind the Gone Green scenario for both capacity and output.

Table 2.2: Comparison of Electricity Output

	National Grid view	RES
Electricity:		
Wind Cap & TWh	19.4 GW offshore 12.9 GW onshore = 98 TWh	14 GW offshore 14 GW onshore = 85 TWh
Other Renewable TWh	49 TWh (biomass 18, hydro 6, Tidal & Wave 6 & other 19 {incl CHP and solar PV})	40 TWh (biomass 16, hydro 3, Tidal & Wave 8 & other 13)
Total Renewable	147 TWh	125 TWh
Renewable %	36%	32%

[4] http://www.berr.gov.uk/files/file38972.pdf
[5] http://www.berr.gov.uk/files/file46779.pdf

21. The key differences from the RES document are highlighted below:

- Offshore wind – 19.4 GW of offshore wind by 2020 is assumed credible due to a higher anticipated build rate than that used in the RES document (particularly in the final years up to 2020).
- Onshore wind – only 12.9 GW of onshore wind is assumed credible.
- Slightly higher contributions from other renewable technologies, e.g. tidal/wave, biomass, CHP and solar.

22. The electricity demand forecasts include allowances for growth in the number of electric vehicles and the electricity demand for heat pumps. This has the effect of negating the savings made from greater energy efficiency and results in a virtually flat demand level out to 2020.

23. The Gone Green scenario results in 36% of total electricity demand being met from renewable sources by 2020. This combined with contributions anticipated from the heat and transport sectors results in the 15% share of the EU 2020 target being met. This background also ensures that the UK remains on the 'flightpath' of emissions reduction to 2050.

Generation Background Considerations

24. In order to meet the average cold spell (ACS) peak electricity demand, system design studies are undertaken using a twenty percent plant margin. In doing this the risk of plant unavailability is taken into account as part of the system development study process. Generation that contributes to meeting this demand is built up using a ranking order based on anticipated cost to the generator of operating its plant and is therefore fuel or flexibility dependant.

25. The ranking order is highly dependent on the generation and demand pattern assumed. In addition, the wind generation is the most significant contributor to the renewable generation portfolio within this study and, as with most renewable generation types, cannot be guaranteed to be available when required. This intermittency results in an increase in the likelihood of plant being unavailable to meet the ACS peak demand. A larger plant margin is therefore required. For the purpose of this study an assumed availability of 40% for wind generation contributing to meeting ACS peak demand has been used to determine the contribution required from conventional plant.

26. Conventional generation contributing at peak is therefore determined by subtracting the calculated available wind capacity from peak demand to give the demand that will be met by conventional generation. A plant margin of 20% is applied to this demand level. Therefore a greater installed wind capacity will result in a higher overall required plant margin to meet demand. In planning transmission network capacity requirements, the further one moves towards the future, the more uncertain the likely generation and demand pattern becomes. Therefore it is general practice to develop a scenario that represents one possible

future outcome for analysis as well as to undertake an investigation of various sensitivities around this scenario to identify the effects of a change in these assumptions. The sensitivities investigate different closure patterns, alternative new plants and the re-phasing of new generation. All sensitivities considered must still meet the target for renewable energy and emissions.

27. In developing the generation Gone Green scenario for electricity a number of factors were taken into account to ensure the targets for both renewable energy and emissions were met. These factors included analysis of:

    - closures of existing plants due to various legislation & age profile;
    - contracted new connections for all types of plant;
    - potential and location for offshore wind;
    - new fossil fuel generation and the potential for CCS;
    - potential build rates for wind and new nuclear;
    - development of micro generation;
    - demand side response;
    - energy efficiency;
    - new sources of demand, e.g. electric vehicles & heat pumps;
    - intermittency of renewable generation and the requirement for backup.

28. All these factors have been brought together to produce a generation background for each year out to 2020. The next stage is to run the generation scenario through a dispatch model that calculates the contribution from each plant type to meet demand over each year. To enable this calculation, a ranking order of generation is created which allows for the availability of plant and the cost of generation. Basically renewable generation is placed to maximise its output followed by nuclear, newer fossil fuel plants (particularly if fitted with CCS) with the older fossil fuel plants, pumped storage and interconnectors providing the marginal plant. This ranking order is then used to determine what reinforcements are required to the transmission network.

Renewable Capacities and Locations

29. The most mature renewable generation technology that could be installed in the quantities required to meet the EU target is wind. Wind therefore makes up the largest proportion of renewable generation by 2020 and has a predicted installed capacity of around 30 GW by 2020. Wind generation is split into on-shore and offshore technologies with on-shore being the more mature. The installation of wind generation has therefore been heavily skewed towards on-shore solutions for the earlier years and offshore generation for the latter years up to 2020. The effect of this is that the majority of new generation being installed is in Scotland up to 2015 where the highest level of on-shore wind resource is available. Beyond 2015 the majority of new wind generating capacity will

be offshore and in English and Welsh territorial waters. The round 1, 2 and 3 proposals produced by the Crown Estate have been used as a general guide to the location and possible capacity of offshore wind farms. Figures 2.2 and 2.3 show the identified round 1, 2 and 3 wind areas most suitable for generation, while figure 2.1 gives indication of possible capacity by geographical area.

30. Given this disposition of offshore wind generation, it is likely that these areas of the on-shore system will be impacted the most and may therefore require the largest amount of reinforcement to facilitate the transmission of the electricity generated to the demand centres where it will be consumed across Great Britain.

31. The phasing and incremental quantity of transmission connected on-shore and offshore wind generation by geographical location is shown in table 2.3 below.

32. The central background used in this study meets the 2020 target for renewable energy. As can be seen from table 2.3 below the majority of renewable energy in the earlier years is met via on-shore development in Scotland with 61% of installed wind capacity in this region by 2015. This results in a significant increase in required power transfer both between SHETL and SPT and between SPT and National Grid networks. The Crown Estate has recently announced that following a successful application process it will be offering exclusivity agreements to companies and consortia for 10 sites for the development of offshore wind farms within Scottish territorial waters. Therefore whilst there is a strong degree of confidence in the high level of renewable generation forecast for Scotland there may be a greater proportion of offshore wind farms than originally assumed.

33. Other renewable energy technologies considered able to contribute to the overall 2020 target are hydro, pumped storage, biomass and wave/tidal. Of these, pumped storage and hydro are mature technologies with no anticipated capacity changes between 2015 and 2020. The forecast contributions of transmission connected biomass and wave/tidal are detailed in Table 2.4.

		Incremental Installed Capacity (MW):					
		2015	**2016**	**2017**	**2018**	**2019**	**2020**
North East		865	1615	2865	5115	6615	8865
North West		1603	2240	2740	3240	3740	4240
South East		1629	1629	1763	1963	2463	2463
South West		0	0	0	0	500	1500
Scotland	SHETL	3735	4403	4975	5660	6152	6900
	SPT	3166	3329	3575	4005	4255	4500
Wales		299	299	299	729	979	979
TOTALS		**11297**	**13515**	**16217**	**20712**	**24704**	**29447**

Table 2.3: Incremental Installed Wind Capacity 2015 to 2020

	Incremental Installed Capacity (MW)					
	2015	**2016**	**2017**	**2018**	**2019**	**2020**
Biomass[6]	776	776	776	776	776	776
Wave and Tidal	0	50	160	610	1110	1410
Totals	**776**	**826**	**936**	**1386**	**1886**	**2186**

Table 2.4: Incremental Installed Capacity of Biomass and Wave and Tidal Generation

34. The total forecast renewable generation capacity on the GB network rises from circa 19 GW in 2015 to 40 GW in 2020. This compares with the current capacity of around 5.5 GW.

[6] It should be noted that this figure is a sub-set of the total UK biomass use – and relates just to transmission connected capacity and does not include (e.g.) co-firing and small and medium distribution connected capacity.

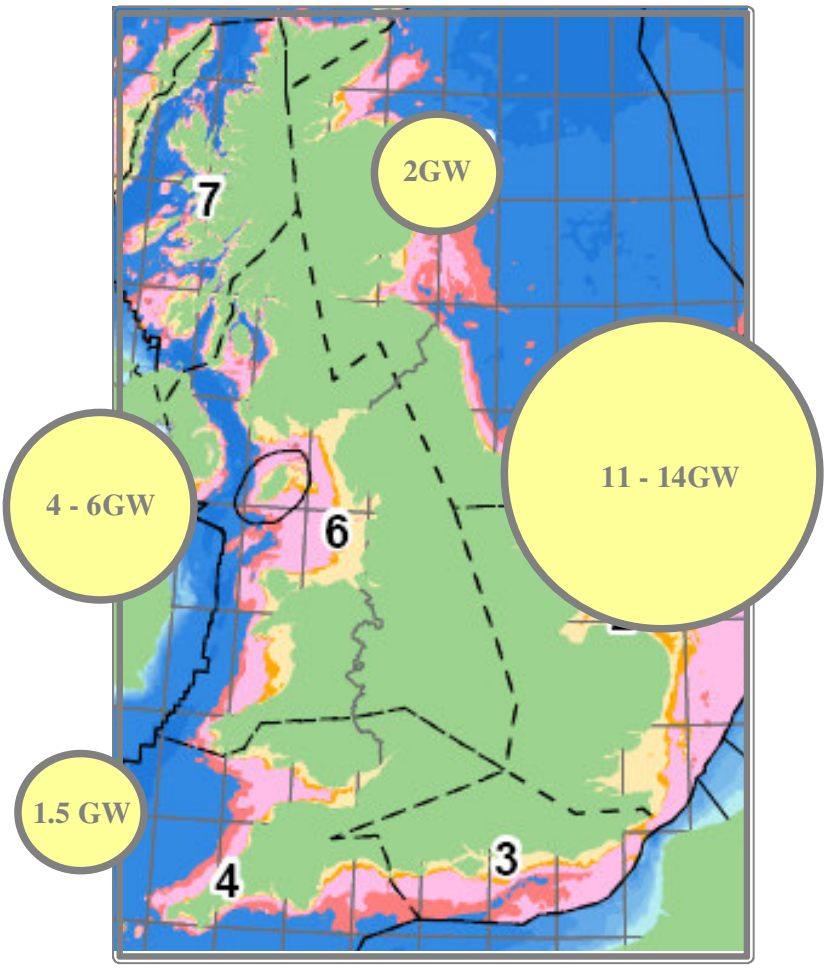


Figure 2.1: Anticipated Distribution of Offshore Wind Farms

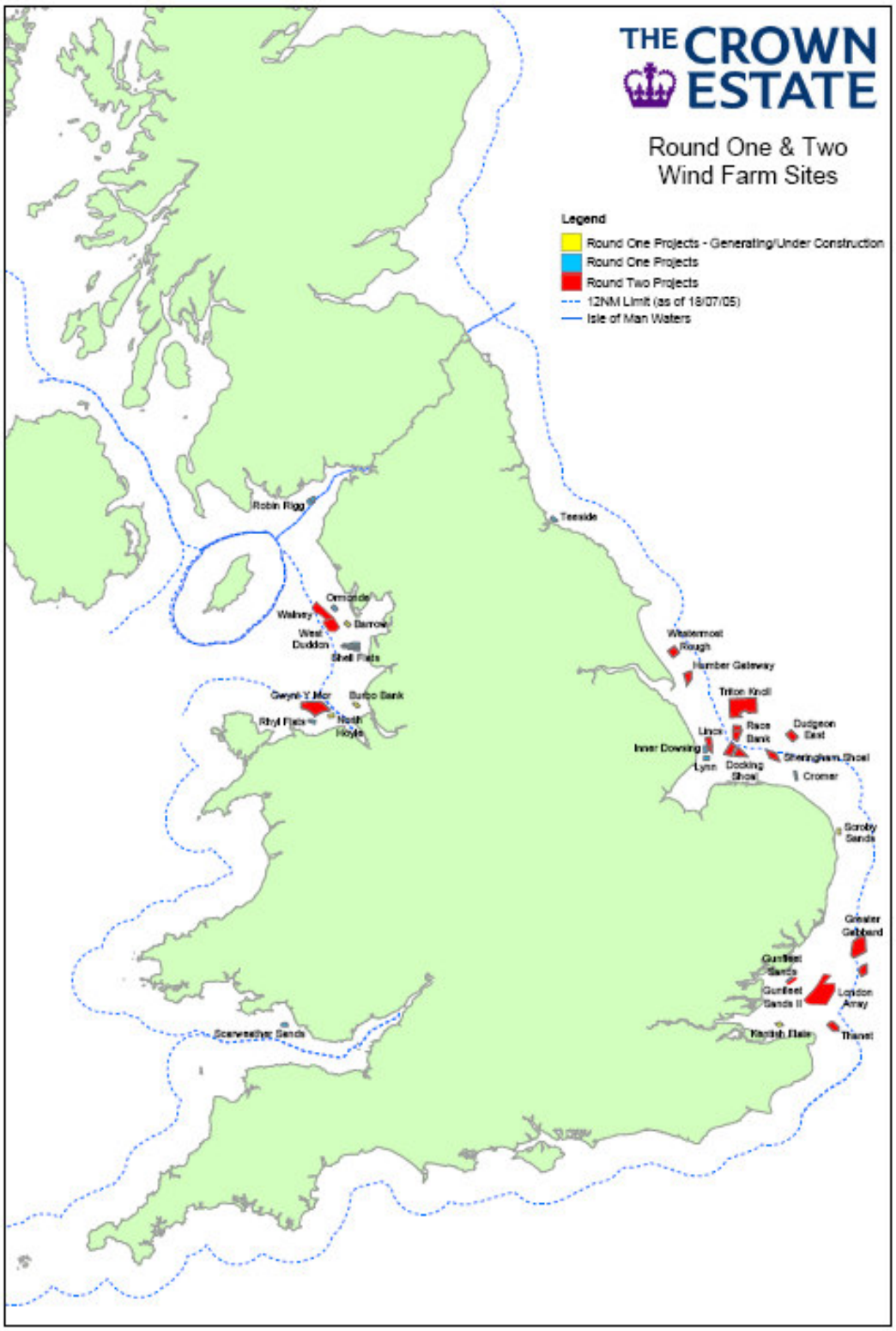


Figure 2.2: Round 1 and 2 Wind Farm Locations

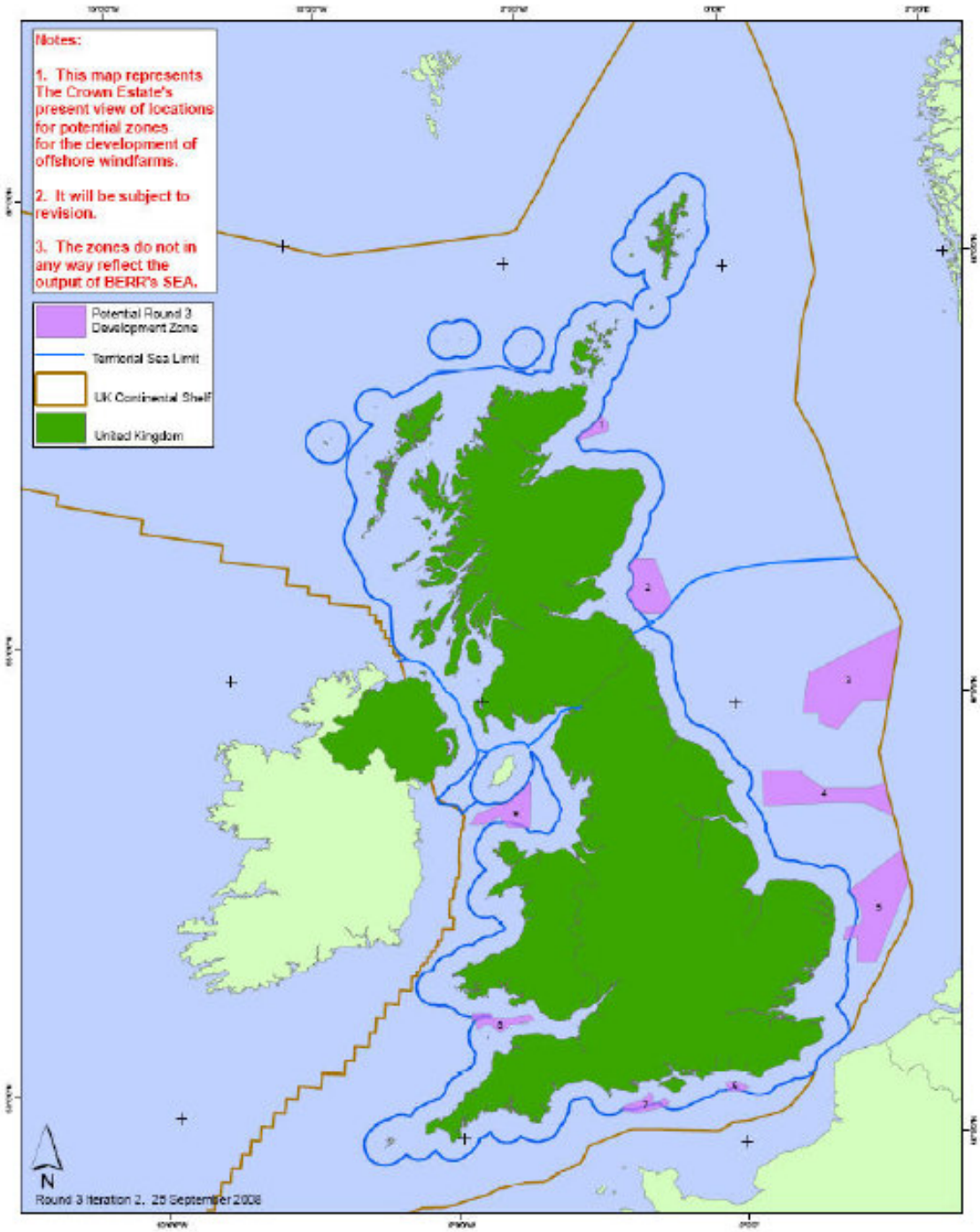


Figure 2.3: Round 3 Potential Wind Farm Resource Availability

Conventional Capacities and Locations

Gas and Coal Fired Generation

35. In order to facilitate large volumes of generation with an intermittent output, such as wind, where the capacity available to meet demand at a given time in the future is less certain than for conventional generation technology, large volumes of more flexible conventional plant will need to be constructed to provide capacity support. Therefore the potential for large volumes of new and replanted gas fired generation, as well as Clean Coal and CHP projects, has been factored into the study.

36. Any conventional fossil fuel plant that does not have flue-gas desulphurisation plant installed has been assumed to close by 2015 under the Large Combustion Plant Directive (LCPD).

Nuclear Generation Connections

37. The Government will undertake a Strategic Siting Assessment (SSA) in 2009, to assess nominated potential locations for their suitability for the deployment of new nuclear power stations by 2025. This exercise is being accompanied by a Strategic Environmental Assessment (SEA). It is recognised that the suitability of any site will need to be assessed through the Strategic Siting Assessment process.

38. The Government noted in the Nuclear White Paper that it expected that nominations to build new nuclear power stations would focus on areas in the vicinity of existing nuclear facilities. This reflected an indication from industry that these are the most suitable sites. The impact of replanting these is therefore considered in the commentary of the results section. New nuclear generation locations with a bilateral connection agreement in place for connection to the onshore transmission system are shown in table 2.5 below while expected closure of existing nuclear site is shown in table 2.6. Sensitivity to closure date has been studied for power stations having a significant impact on transmission system capability.

39. The generation assumptions made for the purpose of this report are entirely independent from and in no way presuppose the outcome of individual planning decisions about projects on particular sites and, in the case of nuclear, the Strategic Siting Assessment (SSA) process.

40. Heysham has existing nuclear generation and is also considered in this report as a potential site for a new nuclear power station. The locations of these sites (which form a non-exhaustive list) are illustrated against the Regional Seas map in Figure 2.4, below. For the purpose of this study the level of new nuclear generation expected to commission by 2020 is 3.3 GW. The generators contributing in the study backgrounds have been taken from tables 2.5 and 2.6, below with locations being chosen to ensure that strategic investment proposed is robust against the possibility of any particular generator connection.

Station	Size (MW)	Contracted Date
Bradwell B	1650	2016 - 2020
Dungeness C	1650	2016 - 2020
Hinkley Point C	3300	2016 - 2020
Sizewell C 1	1650	2016 - 2020
Sizewell C 2	1650	2021 - 2025
Oldbury-on-Severn	1600	2016 - 2020
Hinkley Point	1670	2016 - 2020
Wylfa B	1670	2016 - 2020
Wylfa C 1	1200	2016 - 2020
Wylfa C 2 and C 3	2400	2021 - 2025
Total	**18440**	

Table 2.5: Contracted Nuclear Power Station Openings

Station	Size (MW)	Date
Dungeness B	1080	2016 - 2020
Hartlepool	1200	2014 - 2018
Heysham 1	1140	2014 - 2018
Heysham 2	1300	2023 - 2027
Hinckley Point B	1260	2016 - 2020
Hunterston B	1210	2014 - 2018
Sizewell B	1200	Beyond 2030
Torness	1200	2023 - 2027
Wylfa	980	2010
Total	**10570**	

Table 2.6: Anticipated Nuclear Power Station Closures

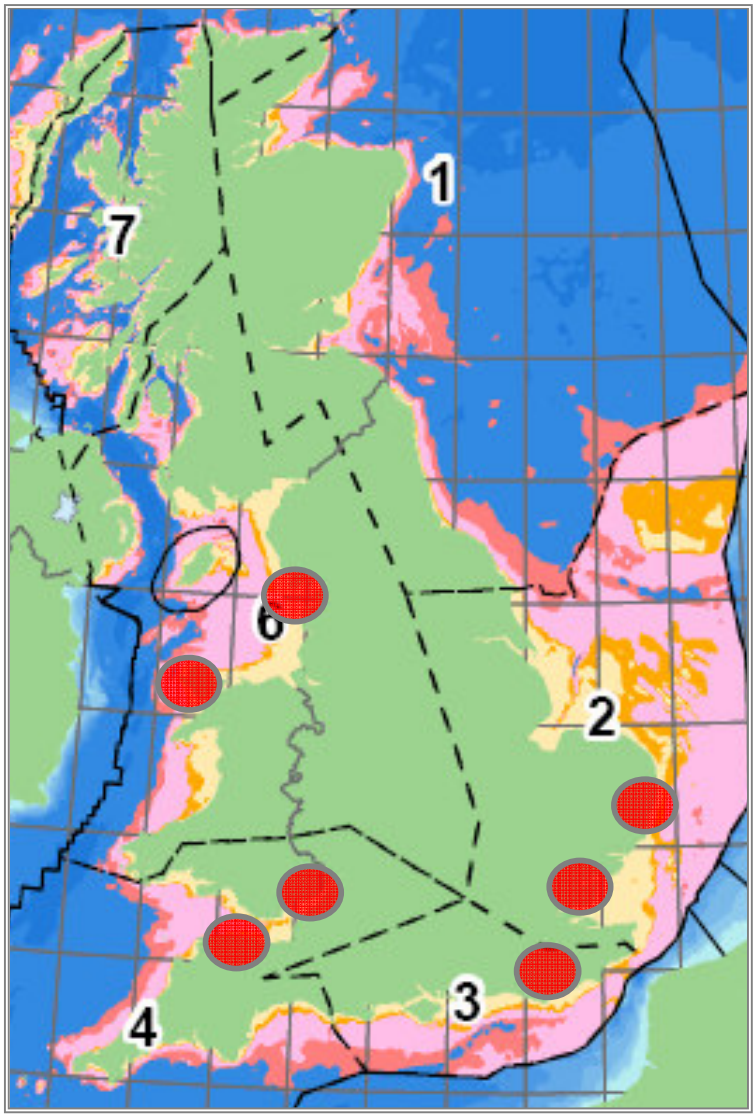


Figure 2.4: Location of Potential New Nuclear Generators considered in this study

International Interconnections

41. The following interconnectors have been taken into consideration either as part of the scenario or as sensitivities in this study:

- Moyle Link;
- French Link;
- East-West Interconnector (Deeside);
- East-West Cable 1 (Pentir);
- BritNed.

42. This consideration is reflected in the location of potential onshore connection points considered and the potential reinforcement requirements identified.

43. The location of these links is illustrated in Figure 2.5, below.

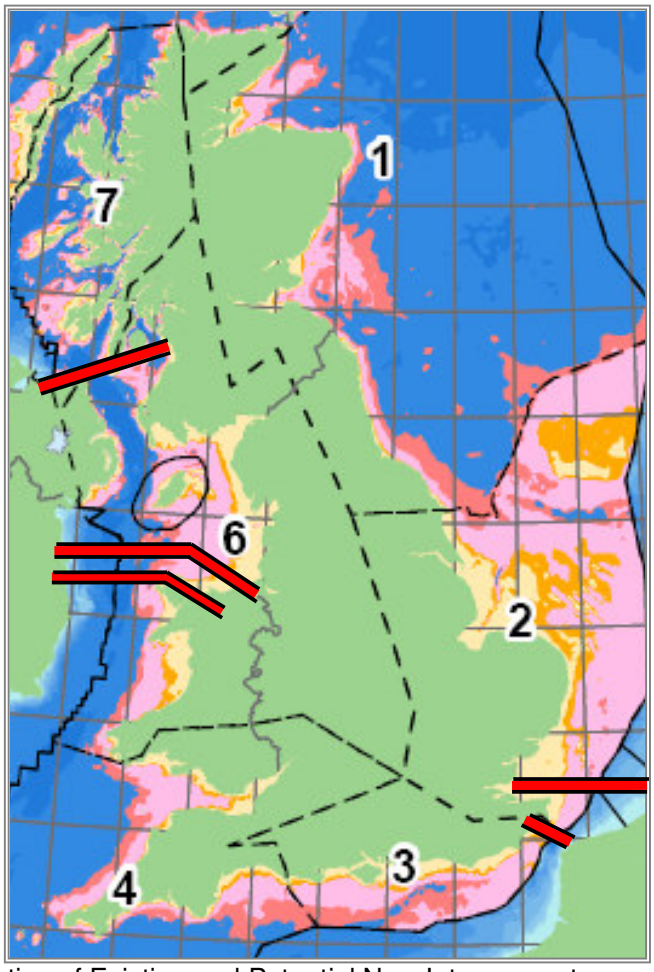


Figure 2.5: Location of Existing and Potential New Interconnectors

Demand

44. The Gone Green demand scenario has been developed utilising an integrated energy model that analyses the main sectoral demands of residential, service, industry and transport. For each sector it considers the various elements of demand within each sector, e.g. space heating, water heating, cooking, electrical appliances, industrial processes and transport modes. When analysing these various elements allowances are made for economic growth, number of households, warming temperatures, the potential for energy efficiency savings, market fuel mixes, CHP development, growth in 'onsite' generation of electricity and heat and new forms of demand, e.g. electric cars and heat pumps. Once a view on total electricity demand has been developed, this can then be split into the demand met from embedded generation and the demand met from large scale generation via the transmission system.

45. The demand forecasts take into account energy efficiency, generic growth (household numbers and number of appliances per home) and new appliances (heat pumps and cars) which result in overall demand remaining broadly flat but with transmission demand falling due to the growth in embedded generation.
    - CHP capacity grows aggressively from 4.4GW to 9GW excluding large scale CHP connected to the transmission network (note that the level of embedded CHP hasn't changed over the last five years).
    - Significant growth of renewable embedded generation from around 3.5GW to 11GW by 2030 with contributions from a wide range of sources including wind, wave, tidal, biomass, hydro and biogas.
    - Microgen incorporates solar PV at sustained build rates equivalent to the largest seen in Europe historically i.e. Germany at its peak, wind and domestic CHP. If the generation build-up in the embedded system does not arise, then larger volumes of renewable generation would be required on the transmission system than envisaged in this report.

    Figure 2.6 below shows annual energy consumption to increase steadily until around 2020 when consumption flattens whilst ACS Peak decline from around 2015; the difference can be deemed to be offset by significant renewable embedded generation.

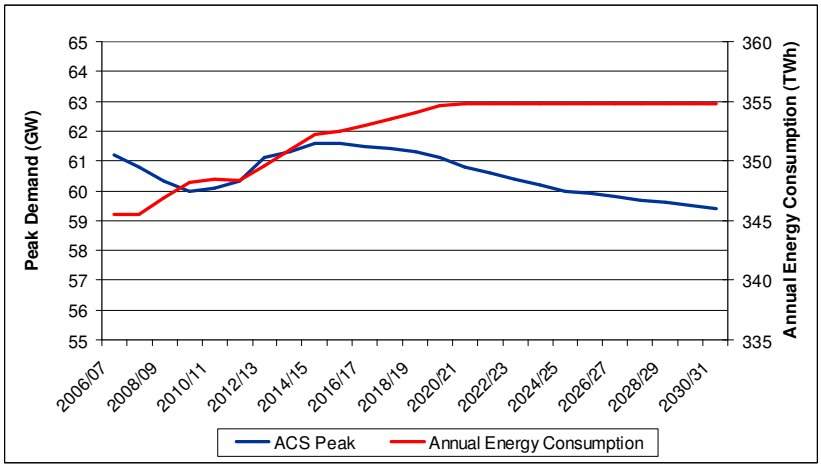


Figure 2.6: Annual Energy consumption and Peak Demand 2006-2030

Chapter 3 - Commentary on Analysis

General

46. The Transmission Licence holders are obliged to plan and operate the GB transmission system in accordance with the GB Security and Quality of Supply Standard (GB SQSS). The GB SQSS is a coordinated set of criteria and methodologies (for example cost-benefit techniques and weather related operation) that the GB transmission licensees use in the planning and operation of the GB transmission system. These will determine the need for services provided to the GB transmission licensees, e.g. reactive power, as well as transmission equipment.

47. The GB SQSS is split into three main design sections; Generation Connections, Main Interconnected Transmission System and Demand Connections. This study is in the most part concerned with the main interconnected transmission system (MITS), however the direct connection of new generating plant to the MITS must comply with the generation connection requirement.

The Main Interconnected Transmission System

48. The transmission system analysis undertaken as part of this report reviewed three design requirement viz; thermal loading of circuits, network voltage performance and generator rotor angle stability.

49. The generation background and generators contributing to meeting demand, as discussed in Chapter 2, the network topology and committed system upgrades and forecast demand have been modelled using National Grid's bespoke power system analysis software and in Scotland using DigSilent Power Factory and PSS/e.

50. For the purpose of understanding system performance, the need or otherwise for transmission reinforcement and for describing opportunities, it is useful to divide the system up and consider power transfers across certain critical boundaries. When analysing the boundaries the power transfers across them are wholly dependant upon the studied generation background. To ensure that the results are robust against possible variations in the generation and demand background, the power flows are flexed by altering generation and demand either side of the boundary. This is done based on an agreed methodology described in GB SQSS Appendix C. Figure 3.1 shows the generic boundaries as studied in the Seven Year Statement[7].

51. Further sensitivities were also considered to take account of the intermittency of wind generation and in particular where there is significant potential for weather variations either side of a transmission boundary. For example the boundary between Scotland and England

[7] http://www.nationalgrid.com/uk/Electricity/SYS/

where there may be significant wind resource in Scotland but much less as one moves further south through England or vice versa.

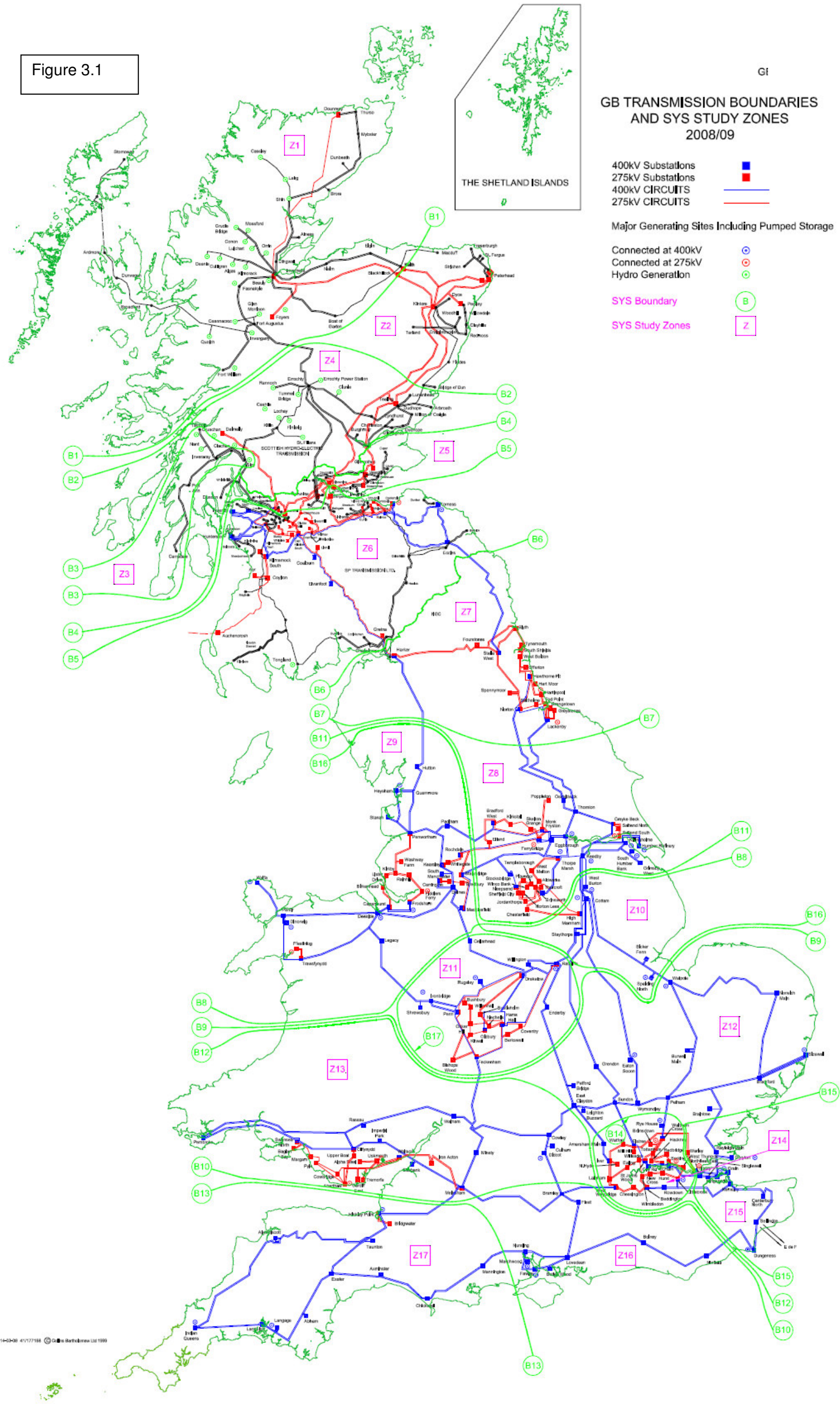
52. The current GB Security and Quality of Supply Standard (GB SQSS) was used in determining the reinforcements necessary under the scenarios. In determining wider infrastructure requirements we have assumed a high level of network sharing. By applying the GB SQSS against the scenarios and appropriate sensitivity studies, a range of potential power transfers can be determined at winter peak. These transfers are not necessarily the maximum transfers and may be significantly higher at off-peak times, particularly in areas where there are significant volumes of wind generation. The impact of our sharing assumptions and the potential for increased transfers is considered in more detail in the Cost Benefit Analysis (CBA) described in Chapter 12.

53. Even with a high level of assumed sharing, there may be opportunities for greater sharing of existing transmission capacity due to the relatively low utilisation of renewable intermittent generation, together with the increased margin between installed generation capacity and demand. A Fundamental Review of the GB SQSS and a Transmission Access Review (TAR) are currently being conducted. Whilst this report did not undertake analysis against all variants under consideration by these two reviews, a CBA was undertaken in respect of proposals to reinforce major system boundaries. The level of transmission capacity identified by the CBA should be consistent with the conclusions of both the GB SQSS and TAR reviews, since it ensures that the GB transmission system is designed to give the most economic and efficient solution. Nevertheless, the proposals presented within this report will be subject to further examination in light of the conclusions of the two reviews. These reviews are due to be completed this year, and this re-examination will not impact on delivery of the required network capacity.

Local Generation Connections

54. The connection criteria for new power stations apply only to the direct connection of one or more power stations to the transmission network and require that the connections can carry the rated output of the power station(s) served by them for the contingencies outlined in the GB SQSS. In this context direct connection can lead quite a long way into the transmission system where the output of several power stations is carried by a limited number of transmission circuits, for example North Wales.

Figure 3.1


GB TRANSMISSION BOUNDARIES
AND SYS STUDY ZONES
2008/09
400kV Substations
275kV Substations
400kV CIRCUITS
275kV CIRCUITS
Major Generating Sites Including Pumped Storage
Connected at 400kV
Connected at 275kV
Hydro Generation
SYS Boundary
SYS Study Zones
THE SHETLAND ISLANDS
SCOTTISH HYDRO-ELECTRIC TRANSMISSION
SP TRANSMISSION LTD
Z1
Z2
Z3
Z4
Z5
Z6
Z7
Z8
Z9
Z10
Z11
Z12
Z13
Z14
Z15
Z16
Z17
B1
B2
B3
B4
B5
B6
B7
B8
B9
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B14
B15
B16
B17

Chapter 4 - North of Scotland

SHETL Licence Area and border with SPT

55. The boundaries studied for the North of England and Wales and Scotland are shown in Figure 4.1, below.

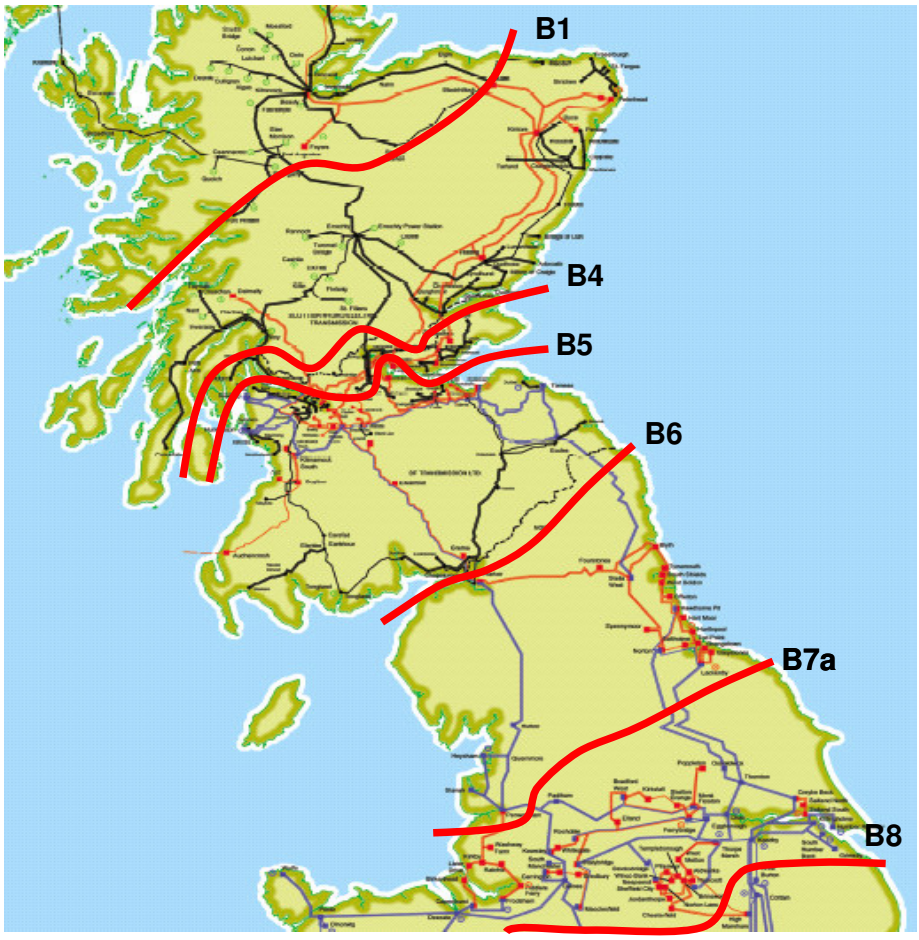


Figure 4.1: Boundaries B1 to B8 Scotland and Northern England and Wales

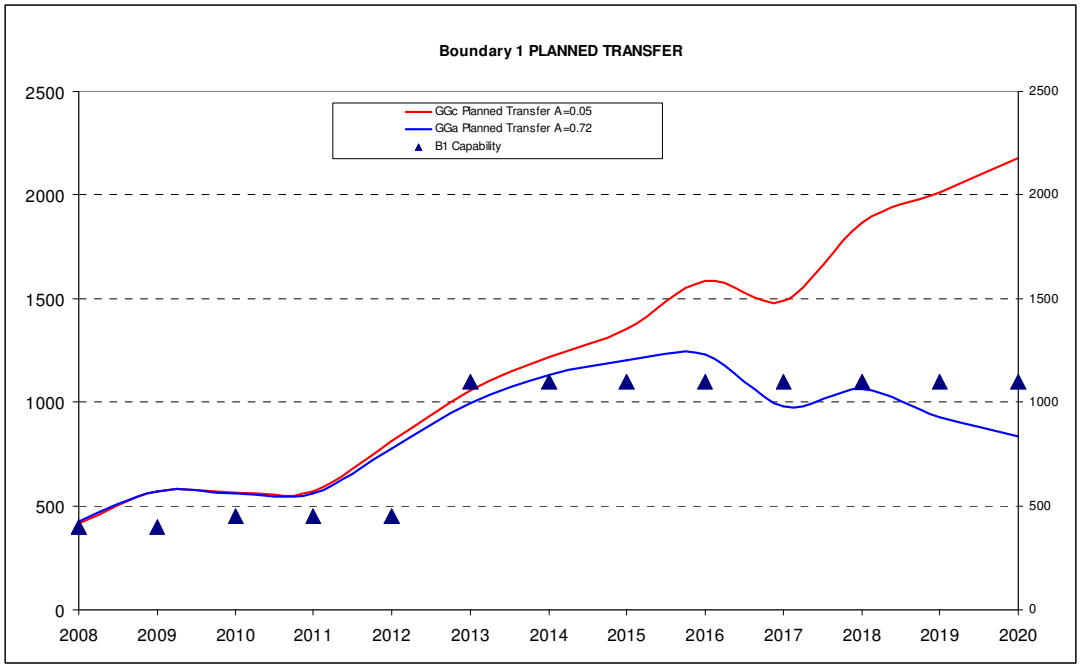
56. The level of renewable generation predicted to connect in Scotland in the period to 2020 allied with a flat demand curve gives rise to a steadily increasing north to south transfer though Scotland.

57. The range of boundary transfers for a given year arises due to the possible treatments of output from intermittent generation, as discussed above and set out in Annex B.

North West Boundary B1

58. The B1 boundary divides the network between Fort Augustus and Errochty in the west, the 275 kV double circuit to the west of Blackhillock and the two 275/132 kV supergrid transformers at Keith.

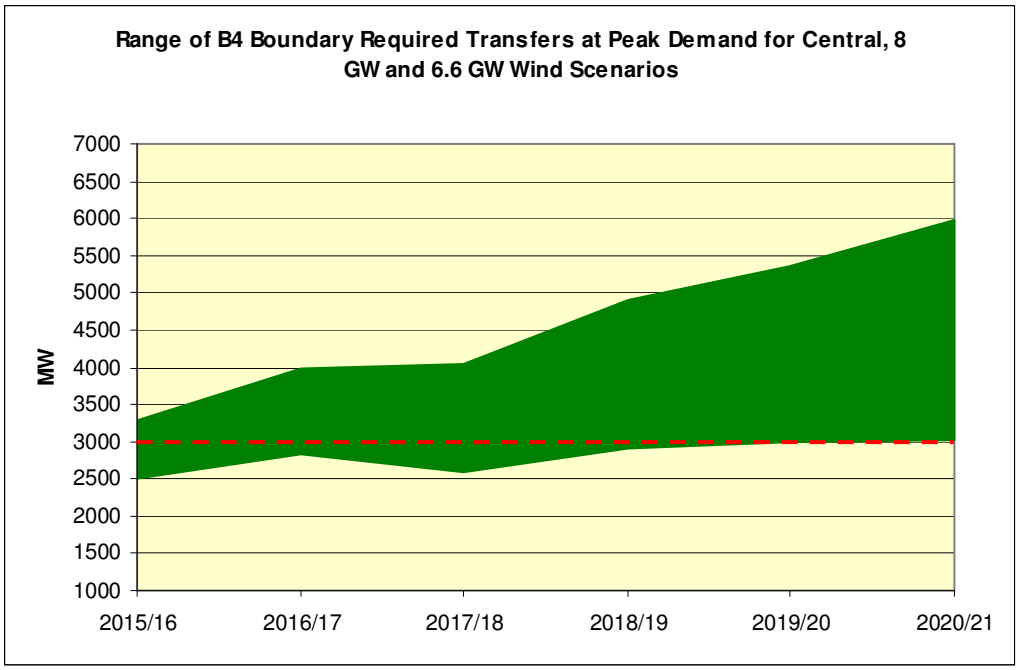
59. The range of transfers across B1 for the three scenarios has been calculated as described in the MITS discussion above and is presented below along with the B1 boundary capability which is adjusted to include currently authorised network reinforcements including Beauly-Denny, which increases the capability by 1100 MW, in 2013. It is clear that, for all but the lowest possible outcome of transfers across B1, further reinforcement will be required across the B1 boundary.



Boundary B4

60. The B4 boundary is the Scottish Hydro Electricity Transmission (SHETL) interface with Scottish Power Transmission (SPT) and comprises the circuits between Errochty and Denny, Tealing and Westfield, Kintore/Tealing and Kincardine, the two double circuit lines between Sloy and Windyhill and the new 275/132 kV substation at Inverarnan in the west.

61. The range of required power transfers across B4 has been calculated as described in the MITS discussion above and is presented below along with the B4 capability which is adjusted to include currently authorised network reinforcements including Beauly-Denny, which increases the capability by 3000 MW, in 2013. It is clear that for all but the lowest possible outcome of transfers across B4 that further reinforcement will be required across the B4 boundary.



Proposed Reinforcements

62. In total the proposed works will further increase the capacity of the transmission system in the north to accommodate approximately 5.5 GW of renewable generation. The reinforced transmission system facilitates the connection of both onshore developments and the sub-sea island links that are planned to reinforce the transmission system.

63. The further upgrades that are required to meet current contracts with generator developers, and consistent with the Scottish Government 2020 targets, have been identified and are included in the Scottish Government's National Planning Framework.

64. The following reinforcements in SHETL's area are referred to as 'least regret' in that there is a strong and robust need case for each one to accommodate the large volumes of contracted renewable generation seeking connection. This means that the risk of these investments being 'stranded' is very small. In addition the works are relatively low impact reconductoring and re-insulation work on existing tower routes, along with development of new substations or extensions to existing substations thus making maximum use of existing transmission routes. These reinforcements are regarded as the first stage of upgrades required to reinforce the north west of Scotland and the transfer capability south to the Central Belt. A second stage of upgrades, described later in the section titled Future Reinforcements, describes the SHETL reinforcements that would be required to accommodate 6.9 GW of renewable generation in the north of Scotland, contributing to the total figure of 11.4 GW for Scotland.

i) Knocknagael Substation;
ii) Beauly-Dounreay Overhead line and Substation Upgrade;
iii) Beauly-Blackhillock-Kintore Reconductor Upgrade;
iv) 400 kV East Coast Re-Insulation and Substation Upgrade;
v) 275 kV East Coast Reconductor Upgrade;
vi) Kintyre-Hunterston Subsea Link.

SHETL Island Links

65. Several large wind farm developments are proposed for the Western Isles and Shetland and as a result SHETL have designed sub-sea links to connect these generation developments to the mainland as described below. The renewable generation on Orkney is growing more organically with a number of small scale developments. A large wind farm development on Orkney has recently withdrawn its application and therefore reinforcement of the Orkney system with a 132 kV cable will depend on the how wind farm and marine generation projects progress in the future.

i) Orkney Link;
ii) Western Isles Link;
iii) Shetland Link.

Boundary Analysis

66. The following tables illustrate the volume of generation that is seeking connection in SHETL's area up to 2020. The ability of the transmission network to accommodate the generation is also displayed along with the reinforcements required.

Boundary B1

67. The capability of the transmission boundary B1 prior to the Beauly-Denny reinforcement is 400 MW at winter peak. After Beauly-Denny is completed the B1 boundary capability increases to 1400 MW. The translation of these network capacities to effective renewable generation that can be accommodated is given in the table below.

NORTH WEST BOUNDARY - B1					
MW	**Existing Network**	**2010**	**2013**	**2015**	**2020**
Connected or Contracted Renewable Generation	*570*	*853*	*1492*	*1975*	*3550*
'Gone Green' Generation Scenario		*583*	*1518*	*2005*	*3600*
Renewable Generation which can be accommodated in Zone	*850*	*950*	*1850*	*3100*	*3100*
Proposed Reinforcement		*Knocknagael Substation*	*1) Beauly – Denny 2) Beauly – Dounreay*	*Reconductor Beauly – Blackhillock - Kintore*	

White background: Current capacity
Blue background: Capacity with reinforcements
Red background: Failure to meet GB SQSS criteria post reinforcement

Boundary B4

68. The capability of the transmission boundary B4, prior to the Beauly-Denny reinforcement is currently 1550 MW at winter peak. After Beauly-Denny is completed the B1 boundary capability increases to 3050 MW. The translation of these network capacities to effective renewable generation that can be accommodated is given in the table below.

SHETL-SPT BOUNDARY – B4							
MW	**Existing Network**	**2010**	**2013**	**2014**	**2015**	**2017**	**2020**
Connected or Contracted Renewable Generation	*900*	*1600*	*2260*	*3500*	*3500*	*4400*	*6600*
'Gone Green' Generation Scenario		*1075*	*2540*	*3080*	*3740*	*5000*	*6900*
Renewable Generation which can be accommodated in Zone	*1500*	*1600*	*2800*	*4700*	*5200*	*5500*	*5500*
Proposed Reinforcement			*1) Beauly - Denny 2)Kintyre-Hunterston*	*Beauly - Kintore Reconductor*	*400 kV East Coast Reinsulation*	*275 kV East Coast Reconductor*	

White background: Current capacity
Blue background: Capacity with reinforcements
Red background: Failure to meet GB SQSS criteria post reinforcement

Future Reinforcements

69. As indicated in Tables above, the 'least regret' reinforcements are insufficient to accommodate all the projected renewable generation by 2020. Consequently, if the forecast generation volumes materialise, further reinforcements will be required on boundaries B1 and B4.

Boundary B1

70. The SHETL network north of Beauly is restricted to two double circuit tower routes, one at 275 kV and one at 132 kV. Given the projected volume of generation in this area and the potential for marine generation in and around the Pentland Firth, further reinforcement will be required to export generation from the far north at the same time as increasing the B1 boundary capacity. This could be achieved in two ways (see Figures 4.2 and 4.3 – right and bottom right) by (i) rebuilding the existing 132 kV infrastructure from Beauly to Dounreay and from Beauly to Blackhillock to give a 275 or 400 kV double circuit or by (ii) construction of an HVDC link between Mybster and the Blackhillock on the Moray coast. It might also be necessary to rebuild a small section of existing 132 kV line between Dounreay and Mybster at 275 kV. Further work will be required to determine the optimal solution for this area, bearing in mind the costs and environmental impact of each option.

MW	***Existing Network***	***2015***	***2020***
Connected or Contracted Renewable Generation	*570*	*1975*	*3550*
'Gone Green' Generation Scenario		*2005*	*3600*
Renewable Generation which can be accommodated in Zone	*850*	*3100*	*4100*
Proposed Reinforcement		*Reconductor Beauly – Blackhillock - Kintore*	*Caithness – Moray Coast*

Boundary B4

71. The capability of the SHETL network to accommodate the forecast renewable generation by 2020 cannot be met from the 'least regret' reinforcements described above. The installation of an east coast HVDC link between Peterhead and the north of England (Figure 4.3 – bottom right) would provide the necessary increase in boundary B4 capacity to accommodate the forecast generation. In addition the HVDC link would

also provide capacity across the B5 and B6 boundaries. An alternative reinforcement for B4 would require the rebuilding of the 275 kV infrastructure between Kintore and Tealing at 400 kV. While this would improve B4 it would not provide any capacity on the B5 or B6 boundaries which would require additional works.

MW	***Existing Network***	***2015***	***2017***	***2020***
Connected or Contracted Renewable Generation	*900*	*3500*	*4400*	*6600*
'Gone Green' Generation Scenario		*3740*	*5000*	*6900*
Renewable Generation which can be accommodated in Zone	*1500*	*5200*	*5500*	*7300*
Proposed Reinforcement		*400 kV East Coast Reinsulation*	*275 kV East Coast Reconductor*	*East Coast HVDC (PEHE)*

Project Costs

72. The following table summarises the costs[8] of reinforcements in the SHETL area.

Project Description	Completion Date	Costs (£M)	
Knocknagael	2010	32	Stage 1 SHETL B1 £180M
Beauly-Dounreay 2nd Conductor and Substation	2012	68	
Beauly - Blackhillock - Kintore Reconductor	2014	81	
400 kV East Coast Re-Insulation	2015	100	Stage 1 SHETL B4 £150M
275 kV East Coast Reconductoring	2017	50	
Caithness – Moray Link (AC onshore or subsea HVDC)	2018	450	Stage 2 SHETL £790M
East Coast HVDC Link (Peterhead – Hawthorne Pit)	2018	340[9]	
Kintyre – Hunterston Subsea Link	2013	124	SHETL Island Links & Kintyre Peninsula
Western Isles HVDC Subsea Link[10]	2013	275	
Shetland HVDC Subsea Link[11]	2014	511	
Orkney AC Subsea Link[12]	2018	180	

[8] Costs are based on desktop analysis using September 2008 prices and do not include on-costs, financing or inflation
[9] SHETL part of East Coast HVDC link
[10] Based on 1*450 MW HVDC link
[11] Based on 1*600 MW HVDC link
[12] Based on two 132 kV subsea cables

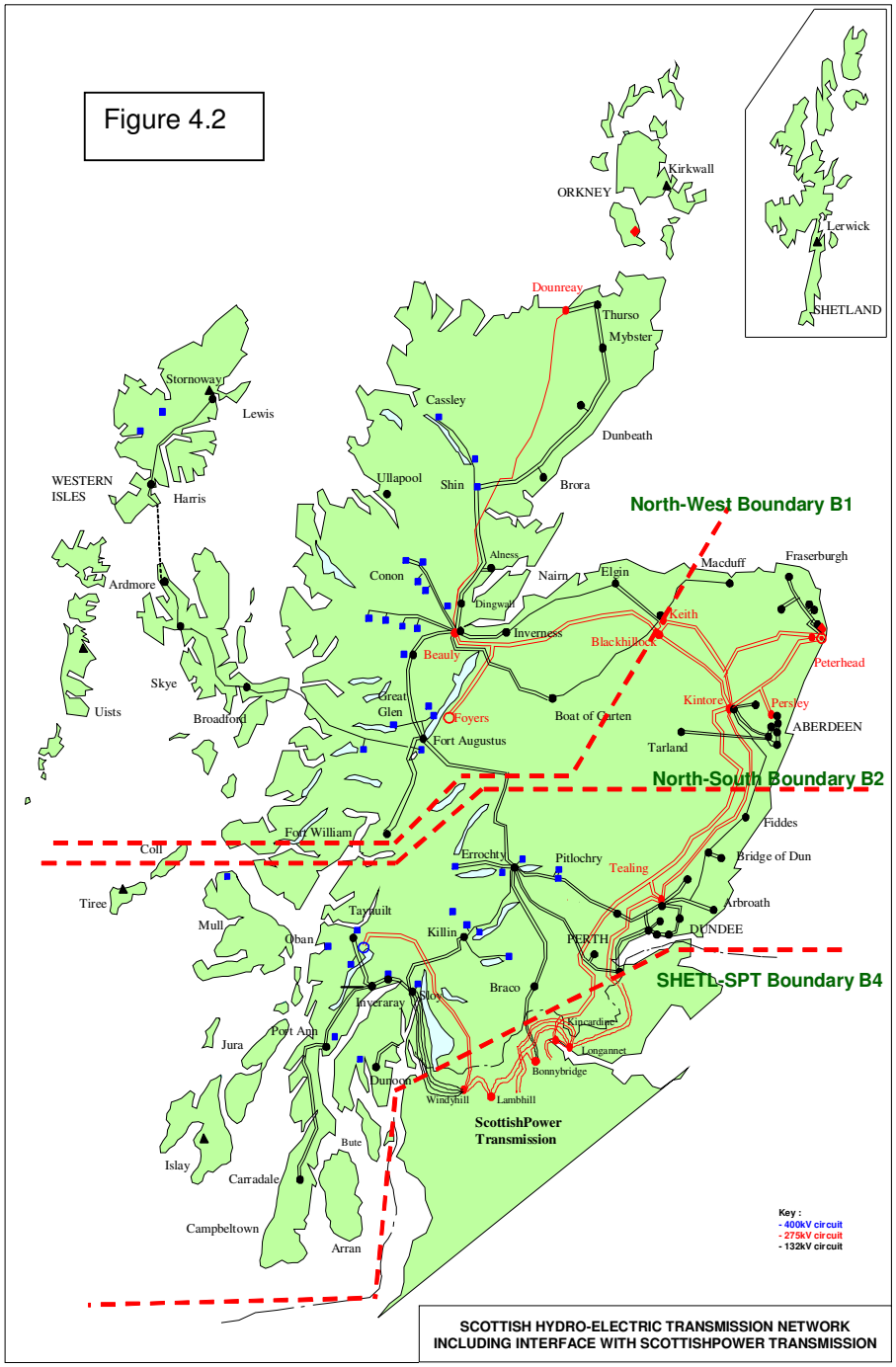
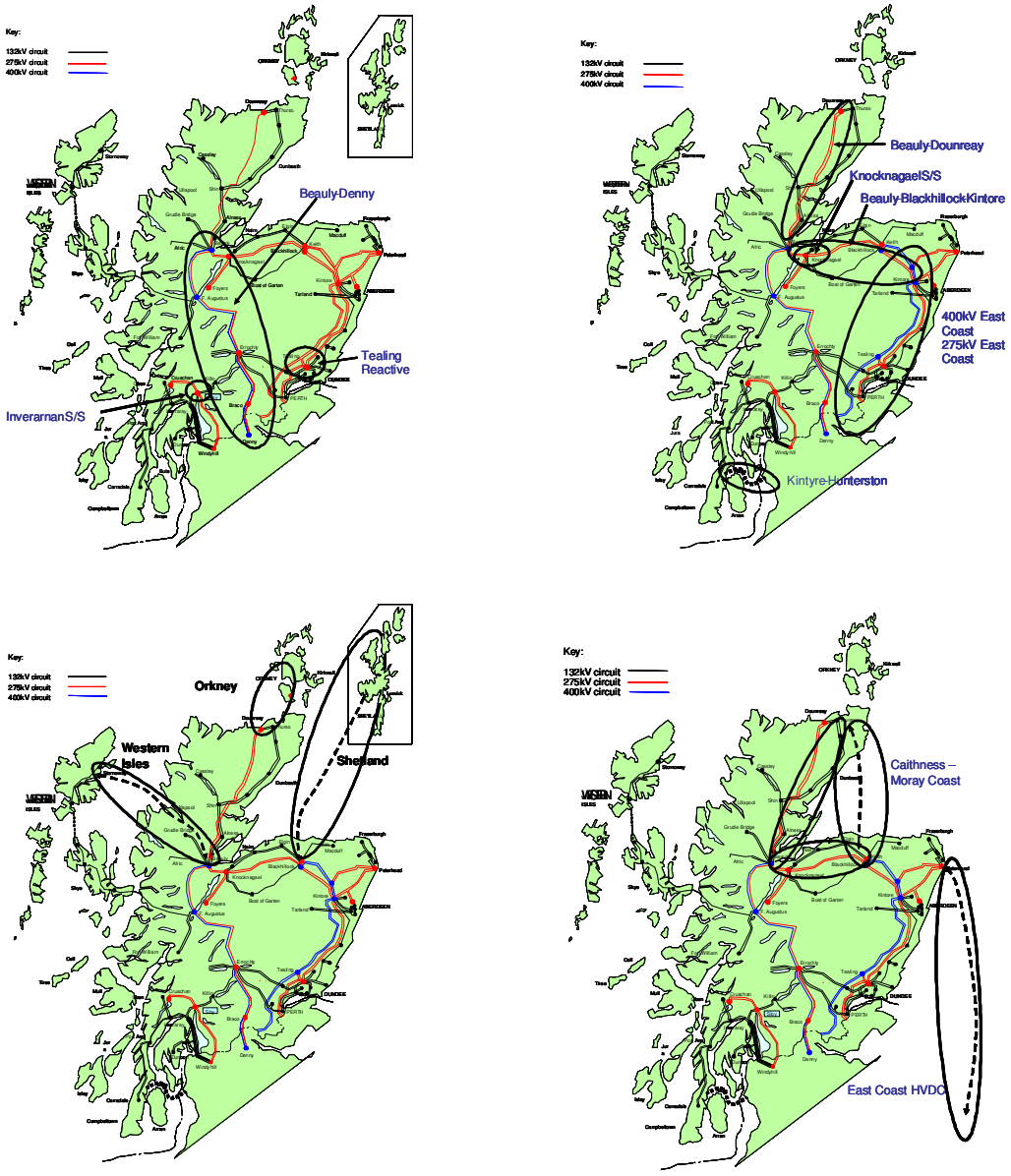


Figure 4.2
ORKNEY
Kirkwall
Lerwick
SHETLAND
Dounreay
Thurso
Mybster
Stornoway
Lewis
Cassley
Dunbeath
WESTERN ISLES
Harris
Ullapool
Shin
Brora
North-West Boundary B1
Alness
Conon
Nairn
Elgin
Macduff
Fraserburgh
Ardmore
Dingwall
Keith
Inverness
Blackhillock
Beauly
Peterhead
Skye
Great Glen
Kintore
Persley
Uists
Broadford
Foyers
Boat of Garten
ABERDEEN
Fort Augustus
Tarland
North-South Boundary B2
Fiddes
Fort William
Coll
Errochty
Pitlochry
Tealing
Bridge of Dun
Tiree
Arbroath
Tayinuilt
Mull
Killin
DUNDEE
Oban
PERTH
SHETL-SPT Boundary B4
Braco
Inveraray
Slow
Kincardine
Jura
Port Ann
Longannet
Bonnybridge
Dunoon
Windyhill
Lambhill
ScottishPower Transmission
Bute
Islay
Carradale
Campbeltown
Arran
Key :
- 400kV circuit
- 275kV circuit
- 132kV circuit
SCOTTISH HYDRO-ELECTRIC TRANSMISSION NETWORK
INCLUDING INTERFACE WITH SCOTTISHPOWER TRANSMISSION

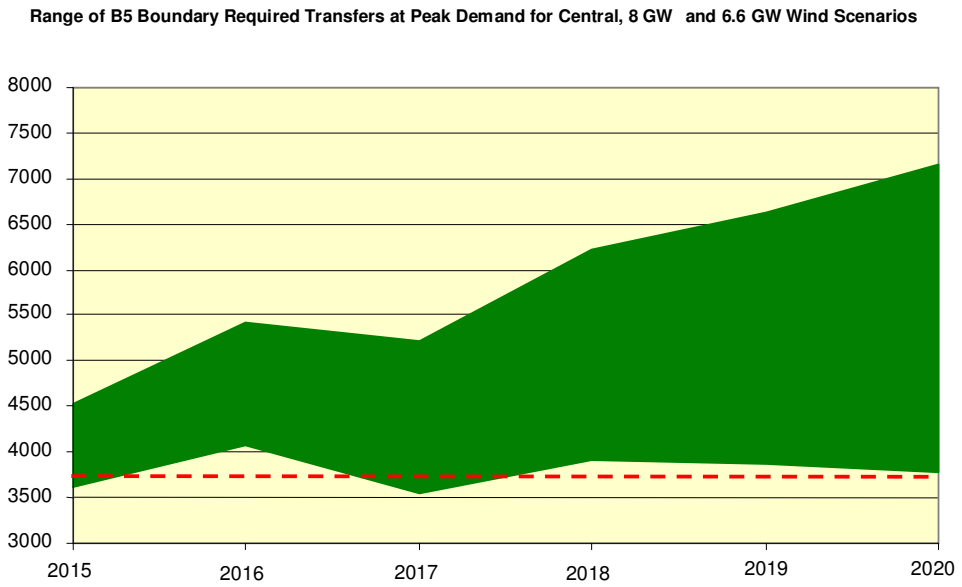
Figure 4.3


Key:
132kV circuit
275kV circuit
400kV circuit
Beauly-Denny
Tealing Reactive
Inveraman S/S
Beauly-Dounreay
Knocknagael S/S
Beauly-Blackhillock-Kintore
400kV East Coast 275kV East Coast
Kintyre-Hunterston
Orkney
Western Isles
Shetland
Caithness – Moray Coast
East Coast HVDC

Chapter 5 - South of Scotland

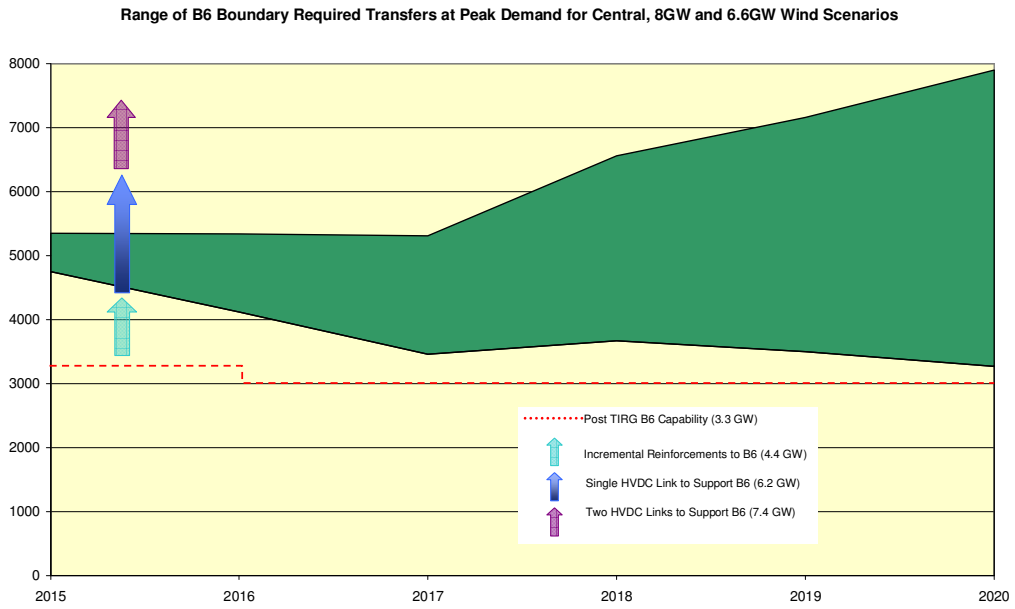
SPT Licence Area and Border with NGET

73. The B5 boundary is the north/south boundary within the Scottish Power Transmission network and comprises three double circuit routes, two operating at 275 kV and one operating at 400/275 kV. By 2015 the B5 capability will be 3700 MW.



74. The B6 boundary is the Scottish Power Transmission and National Grid Electricity Transmission interface and comprises two double circuit 400 kV routes; one on the Western side of the boundary the other on the east. The boundary capability is currently 2200 MW. The transfer limitation on this boundary is required to ensure stable operation of the generation in Scotland following certain system faults and is therefore more dependent upon the impedance of the circuits across the boundary than their thermal rating. Reinforcements to this boundary capability are currently underway and are known as the Transmission Investment for Renewable Generation (TIRG) and TIRG related works. On completion of these works in 2012/13, the boundary will have an export capability from Scotland to England of 3300 MW. The electricity demand within Scotland is predicted to remain at its current winter peak level of around 6000 MW for the duration of this study. The combined output of the synchronised generation that can be accommodated within Scotland at winter peak is restricted to the Scottish demand plus the export capability across boundary B6.

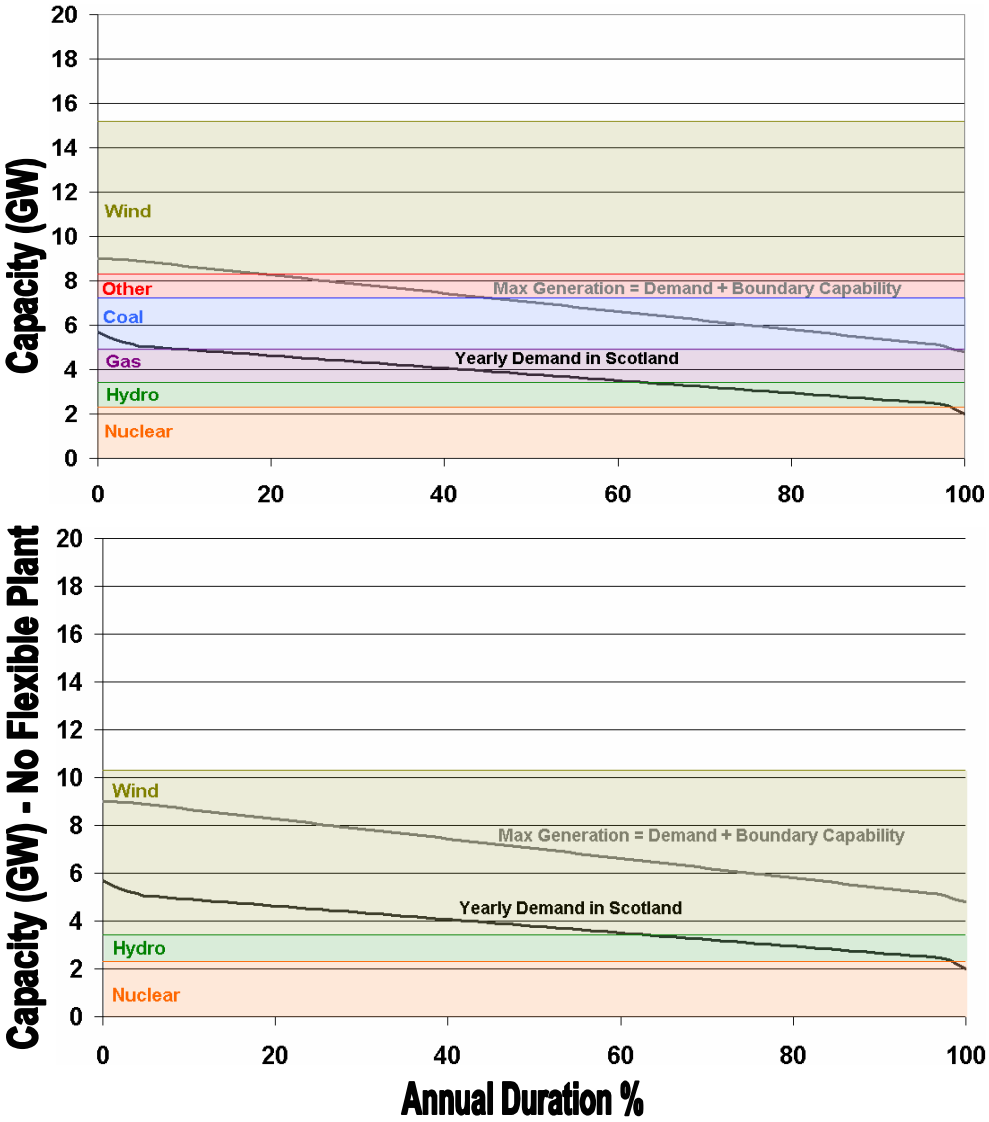
75. The range of possible power flows from Scotland to England across boundary B6 at winter peak are summarised on a combined boundary transfer fan diagram below. The range of transfers for any year arises due to the possible treatments of output from intermittent generation and projected openings and closures of other generation sites. The treatment of intermittent generation takes account of potential differences in wind availability north and south of the boundary. It shows that in all but the lowest generation levels in Scotland for the scenarios considered there is insufficient transmission capacity in the existing network to accommodate the resulting scenario power flows without constraining output of some generating plant. Such low levels of generation in Scotland are considered to be very unlikely.



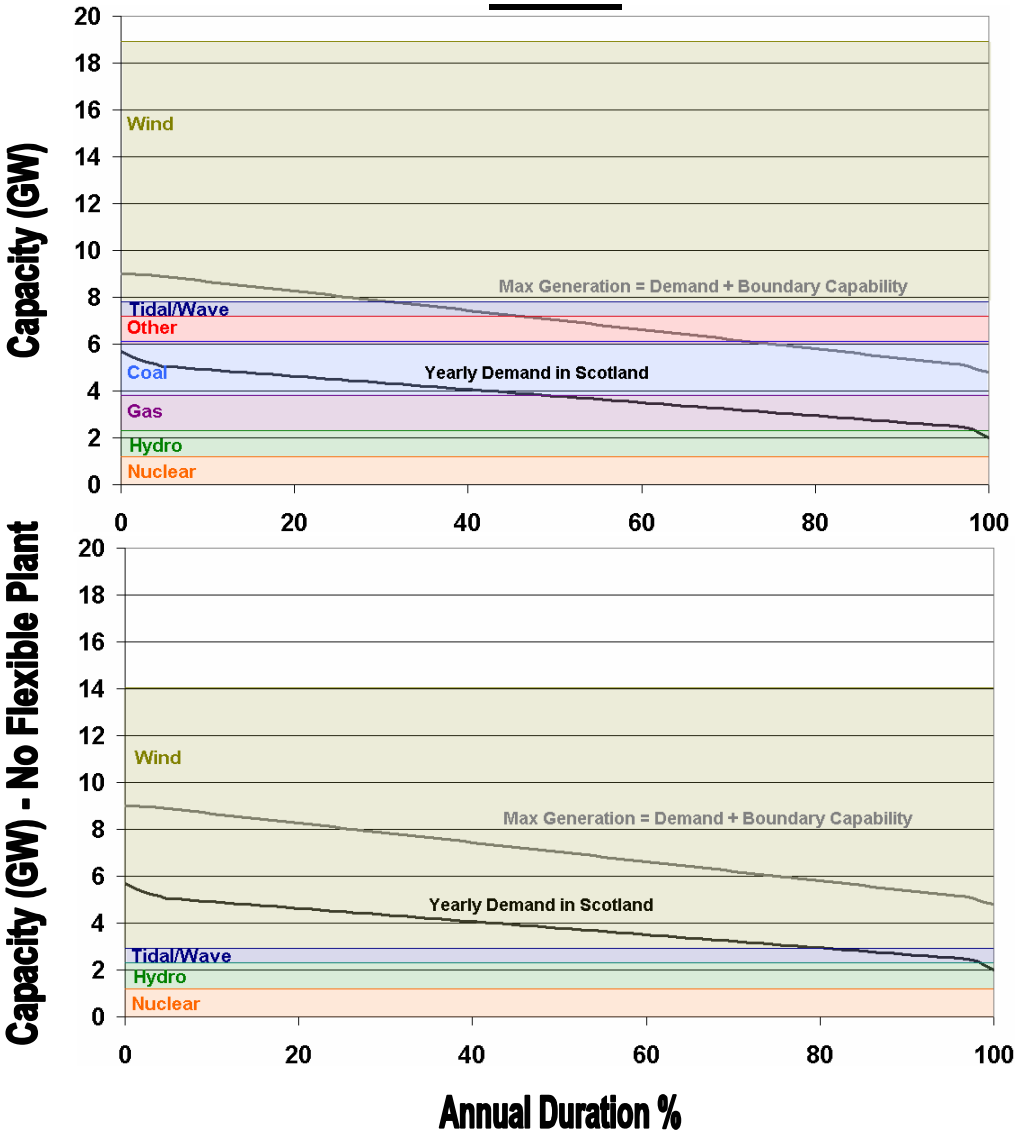
76. If all the non-nuclear thermal plant in Scotland were to be constrained at winter peak and any of the TAR proposals introduced, the result on the power flows from Scotland to England are shown below.

77. With reference to the diagrams below, the upper diagram for 2015 shows how much energy would need to be constrained if all the generation in the scenario for 2015 were to connect without transmission reinforcement across boundary B6. The lower diagram for 2015 shows how much energy would need to be constrained if only nuclear and renewable plant were allowed to generate. The 2020 diagram shows how the situation deteriorates as more renewable plant seeks to connect in Scotland. Output constraints would need to be applied regardless of how the existing capacity is shared and the renewable target for 2015 would be missed.

2015


Capacity (GW)
20
18
16
14
12
10
8
6
4
2
0
Wind
Other
Coal
Gas
Hydro
Nuclear
Max Generation = Demand + Boundary Capability
Yearly Demand in Scotland
0
20
40
60
80
100
Capacity (GW) - No Flexible Plant
Wind
Max Generation = Demand + Boundary Capability
Yearly Demand in Scotland
Hydro
Nuclear
Annual Duration %

2020


Capacity (GW)
Wind
Max Generation = Demand + Boundary Capability
Tidal/Wave
Other
Coal
Yearly Demand in Scotland
Gas
Hydro
Nuclear
Capacity (GW) - No Flexible Plant
Wind
Max Generation = Demand + Boundary Capability
Yearly Demand in Scotland
Tidal/Wave
Hydro
Nuclear
Annual Duration %

Proposed Reinforcements

General

78. Several reinforcement options for the B6 boundary have been studied. The options fall into two broad categories; the first - AC development - by increasing the capacity of the existing circuits and adding new circuits, the second – DC development - by the provision of High Voltage Direct Current (HVDC) links either onshore or offshore.

79. By 2020 the range of possible power flows across the B6 boundary derived from the generation scenarios studied show a potential requirement for a boundary capability approaching 8 GW at winter peak. Following the TIRG works, any further capacity on the existing routes would require a heavier conductor bundle to be installed. The existing towers would be unable to support these loads and hence further thermal capacity increases would require the towers to be replaced with larger and stronger versions for which planning consents would be required. However, this would do little to improve the stability limit and hence rebuilding the existing routes at a higher thermal capacity has not been pursued.

80. The search for a solution to the need for higher capacity has not been restricted to technologies that are currently employed on the GB transmission networks. Series compensation has been used in other countries since the 1950s to increase the power transfer capacity of long AC transmission lines and to improve system stability. Series compensation (SC) has been predominantly used throughout the world to interconnect separate regions within large countries by compensating long power corridors or to connect remotely located generation.

81. Fixed Series Compensation (FSC) allows increased transmission system capability through a reduction in the reactance of the transmission circuit in which it is connected. This improves generator stability by making generators on the system electrically closer to each other. Series capacitors of a fixed value are placed in series with the transmission line in order to achieve the desired increase in circuit capacity. FSC makes the electrical distance between two ends of a line appear shorter and hence improves both angular and voltage stability allowing power transmission at levels well in excess of the natural loading of a line.

82. Series compensation has the potential, under certain conditions, to introduce electrical resonance into the system. These resonances may interact with mechanical torsional resonances in turbine generator shafts of nearby thermal generating plant. This interaction can affect generator performance, or in the worst case, damage the turbine shaft. Resonance became widely acknowledged in the 1970's when a turbine generator shaft was destroyed as a direct result of sub-synchronous resonance (SSR) at the Mohave power station in California.

83. Where potential resonance issues are identified there are a number of options available to mitigate it; the 'safe' level of compensation can be calculated and FSC up to this value can be installed. This option will prevent the occurrence of SSR but will result in a lower transfer capacity. A second option is to install thyristor controlled series compensation (TCSC), this is a more dynamically controllable type of series compensation and would respond rapidly to damp out any resonance that may develop.

84. Additional 400 kV AC double circuits between Scotland and England have been considered. A new double circuit between Eccles and Stella West (east coast) provides less than 1 GW of additional capacity. This is because for a west coast fault, the additional east coast circuit approximately halves the existing impedance which does enhance the stability limit but not sufficiently to be able to take advantage of the full additional thermal capacity. A new double circuit between Kilmarnock and Hutton (west coast) is more effective and for reasons similar to those set out above would increase the capacity by approximately 1.5 GW. To achieve the transfer capabilities required for 2020 with a stable post fault AC network would require both new double circuits to be built. However, the resulting increase in power flows through the north west of England would require significant system reinforcement of the network in this region. Sensitivities to generation in this area, in particular the life extension of Heysham 1, additional wind generation off the North West coast and or new nuclear generation at Heysham could also lead to the need to build new circuits south of Penwortham and significant reinforcements on the network around Liverpool, known as the Mersey Ring.

85. The use of HVDC technology as an alternative solution provides an option that avoids the need for additional reinforcements in the North West while making the solution more robust against possible generation sensitivities. High Voltage Direct Current transmission is the process of converting AC power to DC in order to transmit the power over long distances with minimal losses before being converted back to AC and distributed to loads across the network. This conversion process is carried out at converter stations located at either end of a DC link. HVDC links provide the following benefits to the transmission system:

- Lower losses when transmitting power across long distances.

- Less restriction on cable length. The length of an AC cable is limited due to the reactive power flow caused by the high capacitance of the cable, by using DC this capacitive charging does not occur, allowing for very long cables. This makes HVDC well suited to connecting remote or offshore generation.

- Due to the additional control functions at converter stations HVDC links improve the stability of the AC network to which they are connected.

This can be through controlling power flows, improved damping or AC voltage control.

- HVDC links do not contribute to short circuit levels on the network; if new generation is connected via AC lines, the short circuit level in that area will increase, placing greater strain on protection equipment rating. This is becoming more of an issue as networks become more heavily utilised.

SPT Network

86. The existing transmission system in the SPT area is shown geographically in Figure 5.1 below.

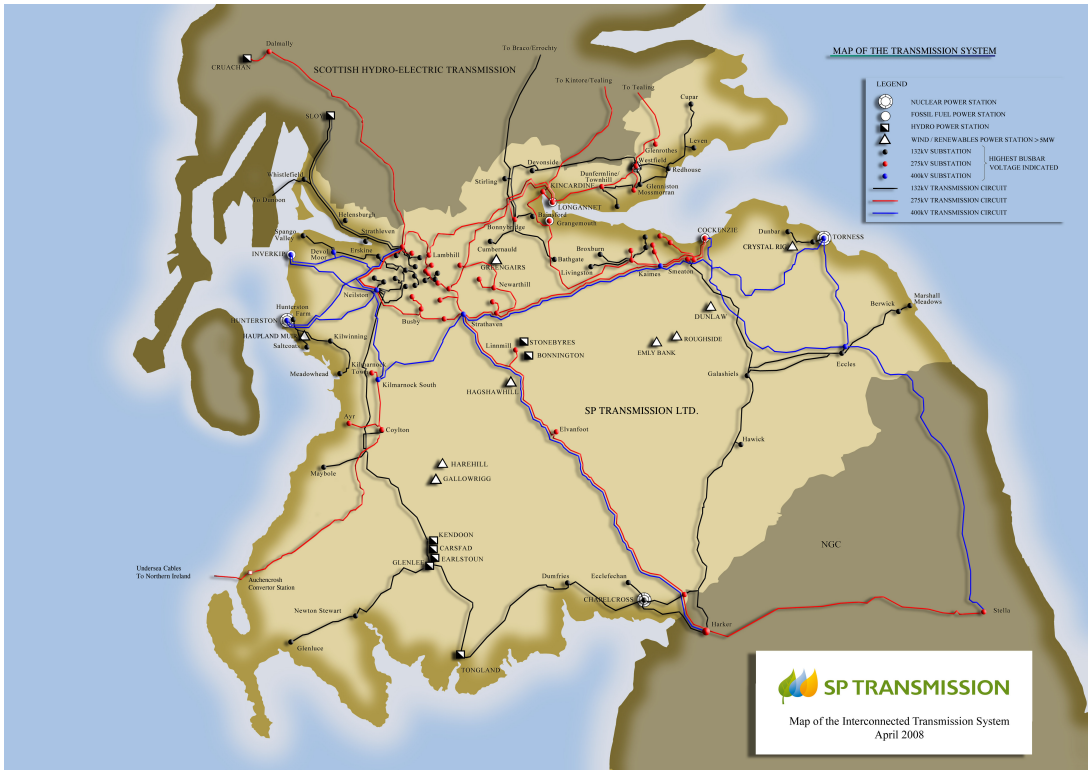


Figure 5.1: Geographic Indication of Existing SP Transmission System

87. The following reinforcements in the SPT area have been identified to support the further integration of renewable generation in Scotland.

    a. East Coast Upgrade to 400 kV Double Circuit Operation;
    b. Series Compensation of SPT-NGET Interconnection;
    c. East-West 400 kV Upgrades;
    d. West Coast Sub-sea HVDC Link.

    These works are indicated in Figure 5.2 and described below.

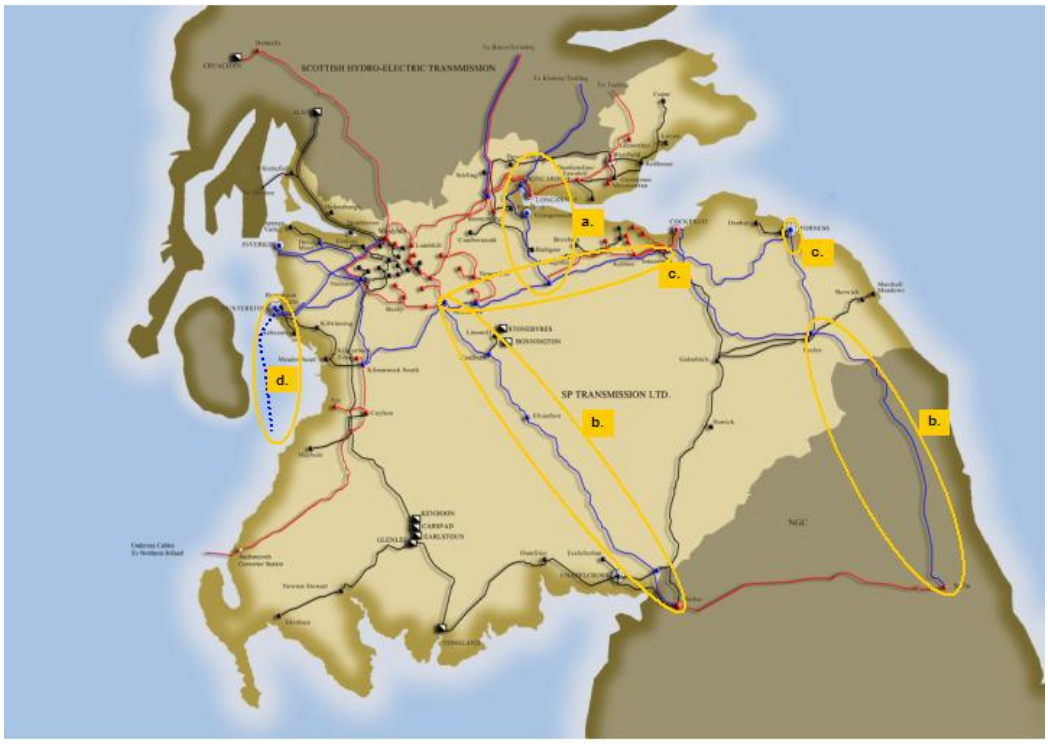


Figure 5.2: Indication of Reinforcements in SPT Area

88. Onshore upgrades in the SPT area, designed to make use of the inherent capability of existing transmission overhead line routes, comprise the three key elements labelled a. to c. above. Together these works form part of the 'Incremental Reinforcement' scheme.

89. The offshore upgrade, labelled d. above, is assumed for the purposes of this report to terminate close to existing 400 kV assets at Hunterston. The scheme is referred to as the Hunterston-Deeside HVDC Link throughout, however a detailed technical and environmental assessment of alternative termination points in the SPT area will form part of the detailed scheme design.

East Coast Upgrade to 400 kV Double Circuit Operation

90. This comprises of the voltage upgrading of the following circuits:

    - Kintore to Kincardine;
    - Kincardine to Grangemouth and Kincardine to Currie.

91. Uprating the transmission corridor south of Kincardine to double circuit 400 kV operation increases transfer capability on Boundaries B4 and B5 and also on B6 due to a reduction in system impedance and consequent improvement in transient stability performance of the combined system.

92. Three new 400 kV substations will be required together with modifications at a number of existing sites.

Series Compensation of SPT-NGET Interconnection

93. The insertion of series compensation in an existing circuit reduces its impedance. The level of reduction is dependent on the electrical size of the compensation fitted. Both NGET and SPT are, at this time, comfortable to insert series compensation to reduce route impedance by around 35% of the original figure.

94. The impact of using series compensation on the performance of generating sets nearby is to be evaluated and where appropriate safeguards developed as part of the detailed design stage, should this proposal be endorsed by the ENSG and expenditure approved by the regulator.

95. Power system analysis confirms that reducing the reactance of the circuits on the following overhead line routes, by approximately 35%, is sufficient to raise the transient stability limit towards the 4400 MW thermal capability:

- Strathaven – Harker 400 kV double circuit;
- Eccles – Stella West 400 kV double circuit;
- Harker – Hutton 400 kV double circuit;
- Harker – Stella West 275 kV double circuit;
- Harker – Hutton 400 kV double circuit;
- Norton – Spennymoor 400 kV double circuit.

96. Initial engineering assessment indicates that existing sites at Strathaven, Coalburn, Elvanfoot and Eccles may be potential locations for series compensation equipment in the SPT area. An environmental assessment will form part of the detailed design stage.

97. In view of the results of power system analysis and initial engineering assessment, cost estimates are based on the following Fixed Series Compensation (FSC) solution:

- Install 1 x 100 Mvar Series Capacitor on the Strathaven-Coalburn 1 400 kV circuit at Strathaven

- Install 1 x 100 Mvar Series Capacitor on the Strathaven-Coalburn 2 400 kV circuit (ex Strathaven-Elvanfoot 400 kV) at Coalburn

- Install 1 x 255 Mvar Series Capacitor on the Elvanfoot-Gretna 400 kV circuit at Elvanfoot

- Install 1 x 255 Mvar Series Capacitor on the Moffat-Harker 400 kV circuit at Moffat or Harker

– Install 2 x 255 Mvar Series Capacitor on the Eccles-Stella west/Blyth 400 kV circuits at Eccles

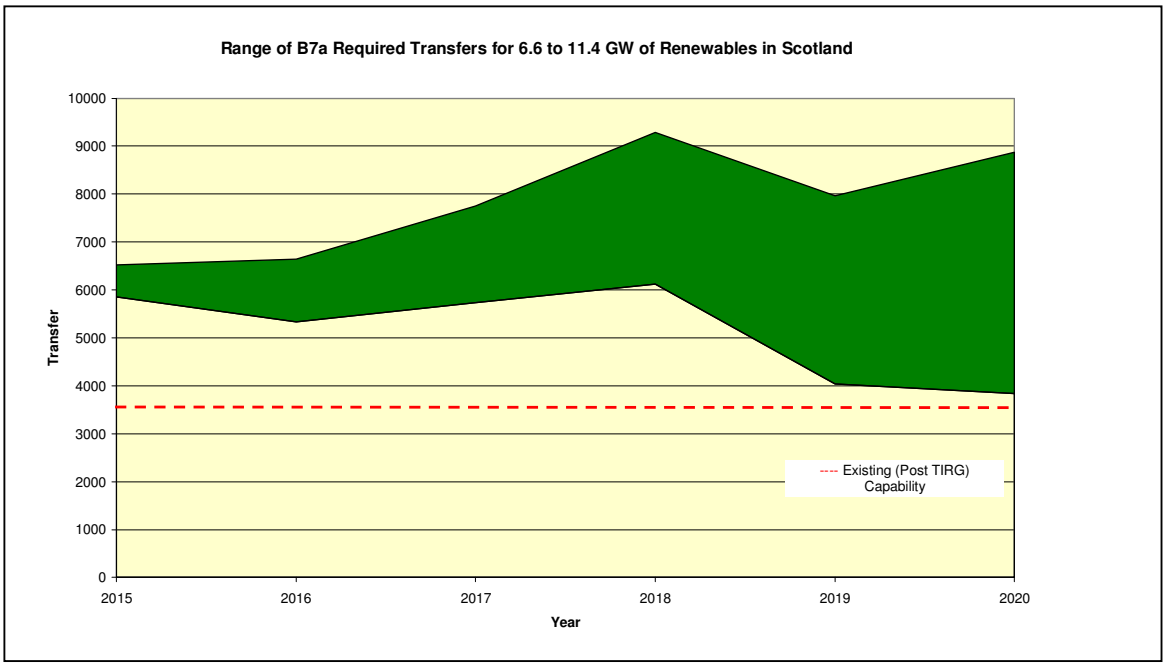
98. For the purposes of this study it has been assumed that no individual circuit should be compensated above 50% and that the degree of series compensation should be minimised for a given transfer level.

East-West 400 kV Upgrades

99. Upgrade the voltage of northern side of the Strathaven-Wishaw-Kaimes-Smeaton double circuit overhead line route. (These works will reduce the system impedance between the northern ends of the two existing SPT-NGET double circuit routes and assist in minimising the degree of series compensation required on the SPT-NGET interconnection.)

100. Install a second 400 kV cable per phase on both of the Torness-Eccles 400 kV circuits.

North of England
Boundary B7a
Figure 5.3



101. The Boundary transfer range calculated for boundary B7a is shown above in Figure 5.3. The fan shows an accelerating increase in cross boundary flows up until 2018. The upper line of the fan relates to the upper renewable generation level in Scotland while the lower line of the fan relates to the 6.6 GW renewable background in Scotland. This is chiefly a consequence of the increasing level of renewable generation commissioning in Scotland and in the North West of England. The reduction from 2018 to 2019 is largely as a result of the current planned

closure dates of both Heysham 1 and Hartlepool nuclear power stations resulting in the loss of capacity of 2.4 GW. This is counteracted in Scenario 1 by the steady increase in renewable generation capacity.

102. The forecast generation to be accommodated by 2020 above boundaries B6 and B7a is set out in Table 5.1 below. These boundaries can currently accommodate 10 GW and 18 GW of generation respectively. By 2020, analysis of the generation scenario shows a boundary capability deficit on B6 of 8 GW and on B7a of nearly 7 GW.

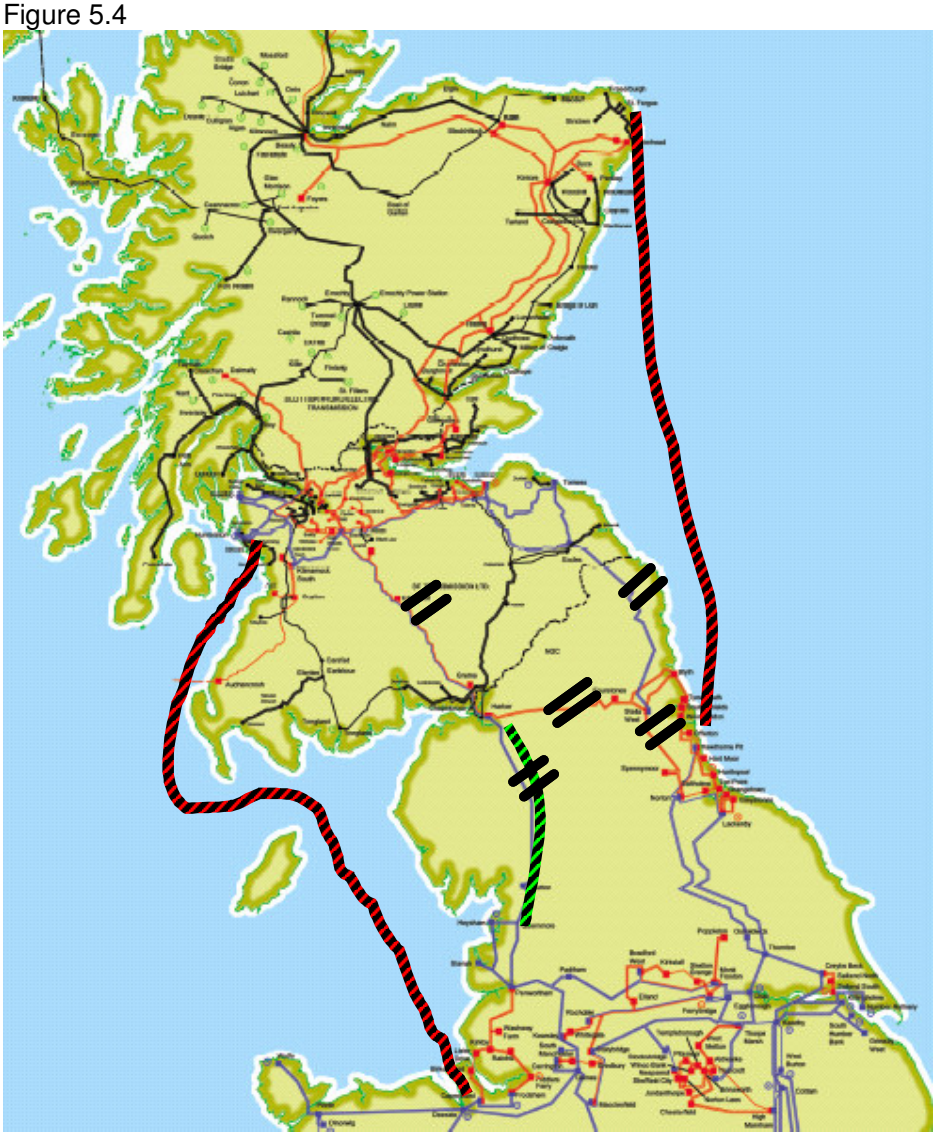
	Network Boundary	Generation Accommodated Currently	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Forecast generation	B6	11.7GW	15.6GW	15.2GW	15GW	15.8GW	17.2GW	18.3GW
	B7a	17.8GW	22.5GW	22.4GW	22.5GW	24.4GW	25GW	24.8GW
Generation which can be accommodated in zone	Boundary 6	10 GW	16.2GW	16.2GW	16.2GW	162GW	18.2GW	18.2GW
	Boundary 7a	18GW	20.6GW	23.3GW	23.3GW	23.3GW	24.5GW	24.5GW

Table 5.1

103. Reinforcements for these boundaries have been identified to remedy this deficit. The optimum balance between AC and HVDC reinforcements are proposed. The AC reinforcements take account of the difficulty in obtaining consents for new overhead line routes and the technical risks of adopting technologies not previously used on the GB system. As a result, it is proposed to install series compensation units at several locations with the overall percentage of line/point to point impedance correction limited to a maximum of 35%. This will raise the stability limit of the AC interconnectors to the thermal limit of 4400 MW. Above B7a boundary, a section of the Harker – Quernmore overhead line will need to be reconductored to match the increased thermal rating of the interconnector circuits.

104. HVDC links are proposed along both the east and west coast. The west coast link will be connected between Hunterston in Scotland and Deeside in Wales. The proposed rating, subject to confirmation from manufacturers, will be 1.8 GW. It can be seen from Figure 5.4 below that the HVDC link straddles boundaries B6 and B7a thereby relieving any additional constraints. The east coast link will connect Peterhead in Scotland to Hawthorne Pit in England. This link relieves any additional constraints on boundaries B1, B4, and B6. Although it terminates above boundary B7a it does provide some additional capacity to the boundary as it helps to balance the east-west distribution of flows across it.

Figure 5.4



105. Together these reinforcements, the onshore AC incremental works, the west coast HVDC link and the east coast HVDC link provide sufficient capacity to accommodate the generation set out in Table 5.1 above, i.e. 18 GW of generation in Scotland and 24 GW above boundary B7a.

Project Programme and Costs

106. The maturity of HVDC and Series Capacitor technologies mean that they can be used on the GB network without increasing risk to security of supply or damage to plant. However, in order to ensure that this is the case it will be necessary to undertake a greater level of detailed analysis than has been carried out at present. It will require the Transmision Owners and manufacturers to work closely together in the design phase of the project to ensure the proposals are robust against all credible combinations of generation, demand, frequency and voltage.

107. The programme for the AC onshore works to increase the transient stability of the existing interconnectors (incremental works) will be undertaken as follows:

Key Activities	Series compensation	Harker- Quernmore
2009	Joint TO system analysis involving suppliers. Develop standards and specifications. Outline Design and site identification	Initiate works, route assessment, programme and obtain outages.
2010	Consult/ Environmental assessment	Order Materials
2011	Submit planning /consent application	Restringing .
2012	Obtain Consent - order materials	Restringing .
2013	Civil Works	
2014	Installation, outages /connection for some sites	Divert connections to Series compensation- energise
2015	Complete connections and commissioning	Divert connections to Series compensation- energise

Table 5.2

108. The activities highlighted in blue require an immediate start if the programme is to complete by 2015 and avoid additional constraint costs as the penetration of renewable generation increases.

109. The programme for the West Coast HVDC link to provide a further 1.8 GW of capacity ahead of the build up in exports from Scotland will be undertaken as follows

Key Activities	Deeside 400kV	DC Converters	Submarine Cable
2009	Design- Integrate asset replacement and DC converter layouts, Consents	Joint TO system analysis involving suppliers. Technical and commercial arrangements to secure market. Create standards and specifications. Identify cable routes.	
2010	Detailed Design & commence manufacture	Detailed design, environmental assessment	Marine and Land Survey, finalise route. Negotiate Crossings
2011	Commence civil Works	Obtain Planning Permission. Start Manufacture	Obtain Consent. Start manufacture
2012	Installation	Partial Site access, commence civil works	Manufacture cable
2013	Commissioning commence.	Civil and installation works	Manufacture and commence cable laying
2014	Complete circuit transfers.	Civil and Installation works. Receive transformers & install	Cable Laying & termination
2015		Commission	

Table 5.3

110. In addition to undertaking the detailed technical analysis on the HVDC link to ensure stability and harmonic distortions are within an acceptable range, it will also be necessary to start work on the layout of Deeside 400 kV substation which is currently planned for asset replacement in 2014, and for which some design work has already commenced.

111. A similar programme for the east coast HVDC will be developed, but as the need for this link is not envisaged before 2018 it is not necessary to start work in 2009.

Costs

112. For the Incremental National Grid Works

Works scope	**Estimated cost £M**	**Source of cost**	**Comments**
Scottish Interconnection			
Series compensation:			
Harker - Hutton	25	Equipment suppliers Budget estimate for a 300 Mvar 400 kV bank = £4.9M, to include for equipment supports & civil/installation works. For additional independent new installation site works, overall site establishment, other civil works, compound fencing etc, and control and communications Line entries require modifications, presume new terminal towers etc. including for consents costs= £ 14M per site - For 2x 300 Mvar site = £23.8M per site. additional costs for system analysis and site design & development costs = £25M per site	
Harker- Stella	25		
Stella- Spennymoor	25		

Harker - Quernmore	100	Generic cost £/km agreed with asset investment and construction	
TOTAL	**175**		

113. For the West Coast HVDC Link

Works scope	**Estimated cost £M**	**Source of cost**	**Comments**
Deeside 400 kV replacement with a 400 kV GIS Substation	80	Separate scheme estimate for asset replacement	
DC Converter Installations	200	Budget estimates and data provided by suppliers	
Submarine Cable	340	Discussions with suppliers Overall cost assuming a mix of sea bed conditions	

Submarine Cable Route survey	2	Consultant budget estimate	
Land Cable Route survey	1	Estimate	
SP System Changes	125	Scottish Power	
Consents	5	L&D	
Engineering, procurement and design	10	Estimate	
TOTAL	**763**		

Boundary B8

114. The Boundary transfer range calculated for boundary B8 is shown below in Figure 5.5. For each of the three scenarios the renewable generation taken out of Scotland is replaced by renewable generation connecting above the B8 boundary. Therefore the power transfers across the boundary are unaffected by these changes to the generation background. The spread of transfers is therefore wholly dependant upon the availability of wind above and below the boundary. As for boundary B7a the transfer requirement increases rapidly, due in the main to new renewable generation up to 2018 and then decreases from 2018 to 2019 with forecast power station closures before rising again with increasing renewable capacity. The works associated with the connection of the east coast offshore wind capacity include reinforcements that improve B8 boundary capability. These reinforcements are discussed in Chapter 8.

115. Additional reinforcement to the western side of boundary B8 is only required for the lower probability sensitivities to the three scenarios. In particular additional new generation on the north-west coast or north Wales coast could trigger a requirement for reinforcements south of Daines substation. The most likely additional generation is new nuclear capacity at existing nuclear sites or the extension of exiting nuclear operating licenses along with very high wind penetration. It is not considered prudent at this stage to invest against the short term excursion above the current capability as this is both short-term and ameliorated by the reinforcements on the east coast. Should new generation apply for connection in the north-west its connection will drive the necessary reinforcement in the appropriate timescales. The increased capacity provided by the investments identified between Humber and Walpole, see later, provide the additional boundary capability required.

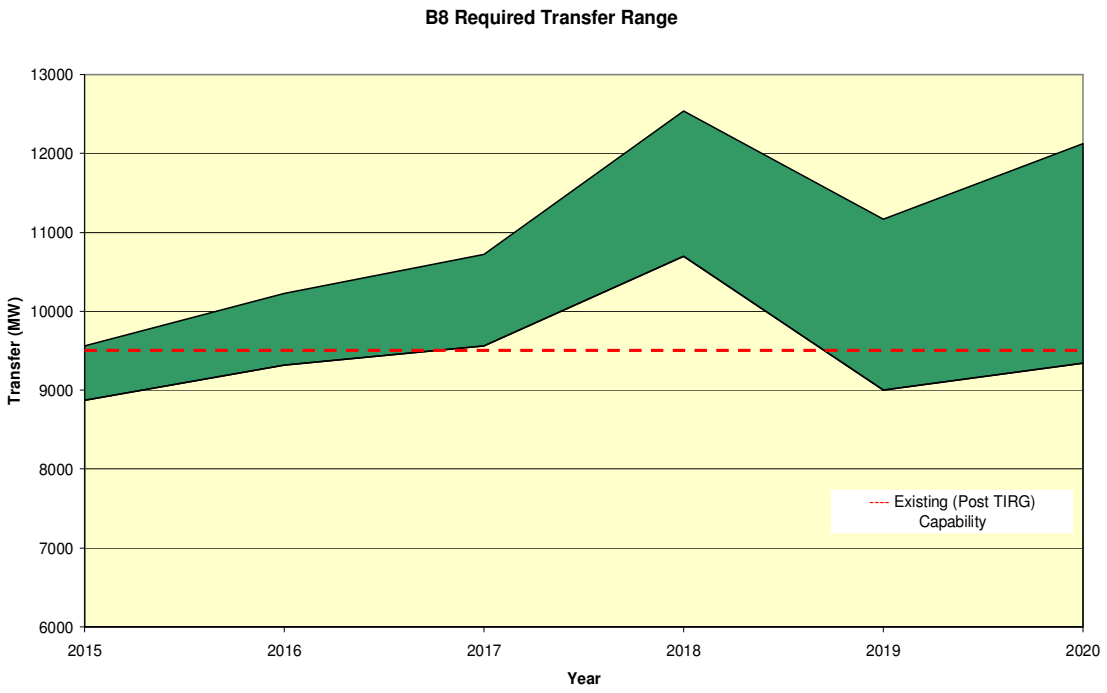

B8 Required Transfer Range
13000
12000
11000
10000
9000
8000
7000
6000
Transfer (MW)
2015
2016
2017
2018
2019
2020
Year
---- Existing (Post TIRG) Capability

Figure 5.5

Chapter 6 - North Wales

116. The network in North Wales is comprised of a 400 kV circuit ring that connects Pentir, Deeside (near Connah's Quay) and Trawsfynydd substations. The majority of the overhead line loop around this region forms a double circuit route. However, only a single 400 kV circuit connects Pentir to Trawsfynydd within the Snowdonia national park, which is the main limiting factor for capacity in this area.

117. There is a double circuit spur (approximately 36 km) out to the coast from Pentir to Wylfa Head near Cemaes that crosses the Menai Strait. Wylfa substation is currently the connection site for the 980 MW Wylfa A Magnox nuclear power station. It is anticipated that Wylfa A station will begin decommissioning in 2010; hence it is omitted from the assumed generation and demand scenarios to 2020. However, it is also assumed that Wylfa will remain a prime site for nuclear replanting and we have assumed a new nuclear power station will have commenced construction by 2020. A double circuit cable spur (route length approximately 10 km) from Pentir connects Dinorwig pump storage station by Llyn Peris reservoir. A 275 kV spur (approximately 7 km) traverses north of Trawsfynydd to Ffestiniog pumped storage station.

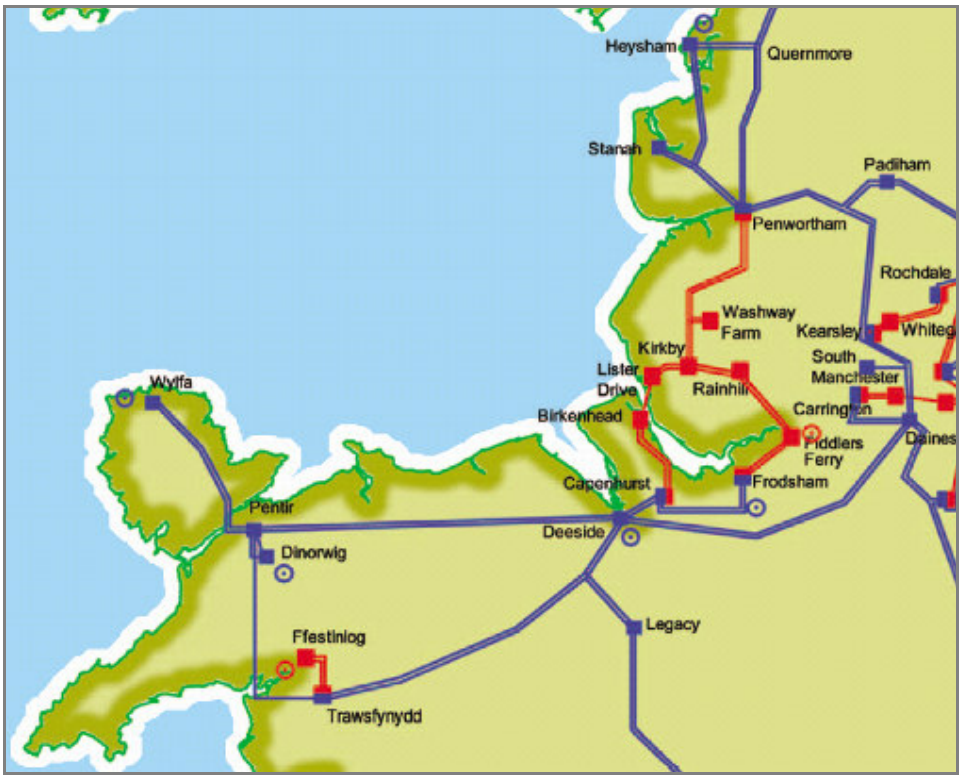


Figure 6.1: Onshore Transmission System in North Wales and the North West

118. Currently, the transmission system in North Wales is being modified to allow for the connection of the 750 MW Gwynt-y-Môr offshore wind generation development. The current proposal for this connection is to

construct a new 400 kV substation to the north east of Deeside linking to the main transmission system via a double circuit between Pentir and Deeside.

119. The scenarios used assume some existing CCGT plant in this region has decommissioned, while Dinorwig and Ffestiniog pumped storage plants continue to remain in service. A 500 MW HVDC interconnector circuit to Ireland from Pentir is contracted for commissioning in 2015. Significant interest has also been shown with respect to the building of new CCGT power stations both on Anglesey and at Deeside. The total amount of existing plant closures in this region is assumed to be 1885 MW in these scenarios and hence some existing transmission infrastructure capacity is released. There exists a potential for 1 to 2 GW of tidal stream generation in the Skerries off Anglesey which may connect by 2030.

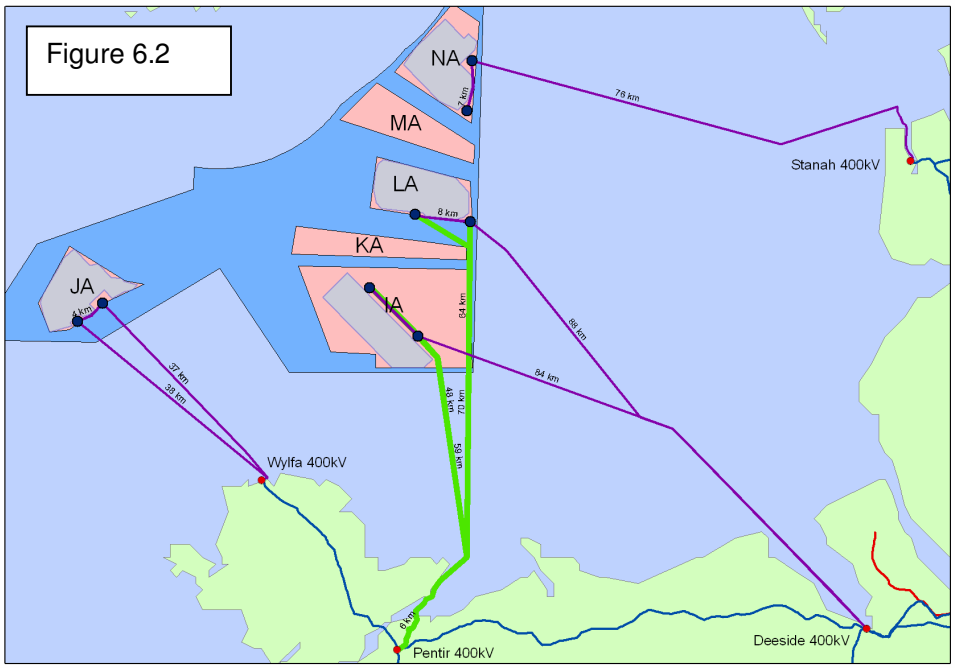
120. The assumed HVDC link from Hunterston into Deeside, the connection of an HVDC interconnector circuit to Ireland form Pentir, pumped storage plant, replanted nuclear generation, gas fired plant and offshore wind farms all compete for the same infrastructure capacity. A summary of generation development in North Wales is set out in Table 6.1 below.

Table 6.1: New Plant in North Wales

Plant	**Capacity**	**Status**	**Connection Site**
Nuclear	5270 MW	Contracted	Wylfa
R3 Wind Farms	Up to 4 GW	Proposed	Wylfa
R2 Wind Farms	735 MW	Under Construction	St Asaph
Interconnector	500 MW	Contracted	Pentir

Offshore Wind Connection Options and Issues

121. The Round 3 wind farm sites released by Crown Estates off the North Wales cost line are shown below in Figure 6.2.



122. The scenarios assume that up to 4 GW of offshore wind farms in the southern Irish sea may connect in this area as the sites released for development are relatively close to landfall compared to many of the sites off the east coast of England. The options for connecting the sites shown above to the onshore shore transmission are:

- HVDC connection to Stannah;
- HVDC connection to Deeside;
- HVDC connection to Pentir;
- AC connection to Wylfa.

123. The estimated costs of the alternative connection options are set out in the following table.

Table 6.2: Alternative connection costs

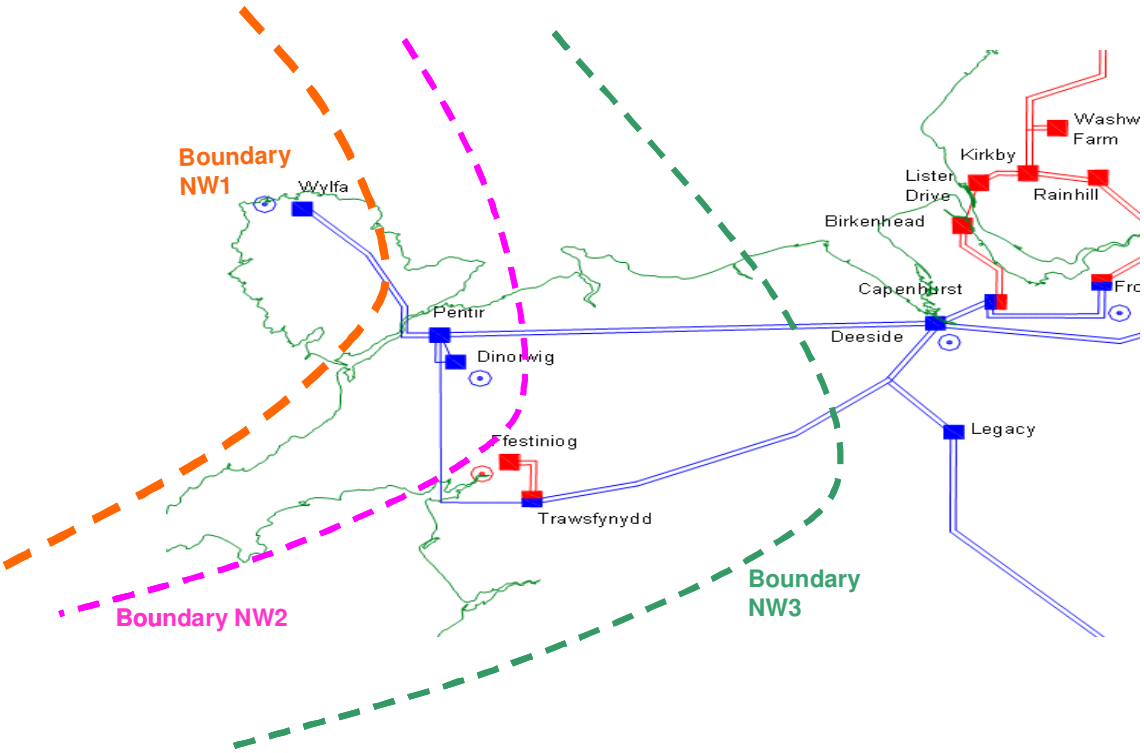
Offshore windfarm (Rd 3)	Deeside (offshore cost)	Wylfa (offshore costs)	Pentir (offshore costs)	Stannah (offshore costs)
NA (1GW)	£400M	£400M	£400M	£400M
IA (1GW)	£470M	£250M	£420M	£450M
LA (1GW)	£420M	£260M	£400M	£470M
JA (1GW)	£500M	£260M	£400M	£500M
Total cost[1]	£1790M	£1170M	£1620M	£1820M

124. The minimum connection costs for 3 GW of offshore wind farms from the southern Irish sea would be an AC solution, landing the cables at Wylfa on Anglesey saving around £500M of offshore costs. The minimum connection cost for landing 1 GW from area NA would be subject to a more detailed engineering assessment.

Onshore Transmission Considerations

125. To determine the generation capacity (existing and new) the transmission system in North Wales can accommodate, the onshore network must be considered against the criteria in GB SQSS. The security criteria in the GB SQSS have been applied across three boundaries as shown in Figure 6.3 below.

Figure 6.3: Transmission analysis boundaries considered in North Wales



126. As a result, the capacity of boundary NW1 is currently 1.32 GW, NW2 is 3.0 GW and NW3 is 3.7 GW.

127. The potential generation to be accommodated in North Wales is set out in Table 6.3. The scenario shows 3 GW of existing generation in 2010, rising to between 5.5 GW and 7.5 GW (including interconnectors) dependent on the penetration of renewable generation onshore in Scotland. That is, 5.5 GW of generation in North Wales assumes 11.4 GW of renewable generation in Scotland, 7.5 GW of generation in North Wales assumes less than 11.4 GW in Scotland.

Assessment of Boundary Capabilities

128. The capacity of boundary NW1 (shown in orange) at 1.32 GW (possibly 1.8 GW following the review of the GB SQSS) is set by the maximum loss of infeed following the loss of a double circuit. The capability is insufficient to accommodate the low estimate of offshore wind alone at 2.5 GW, regardless of whether the nuclear site at Wylfa is replanted or whether any of the proposed CCGT plant on the island materialises. Further capacity can only be provided by the construction additional circuits between Wylfa and Pentir.

129. The capacity of boundary NW2 (shown in purple) is limited by the single 400 kV circuit between Pentir and Trawsfynydd following the loss of the

Pentir – Deeside 400 kV double circuit. The 132 kV single circuit owned by Manweb is strung on the opposite side of the tower to the Pentir-Trawsfynydd 400 kV single circuit. To increase the capacity across boundary NW2 to be compatible with the proposed additional capacity across NW1, the 132 kV circuit needs to be adopted as a transmission circuit and uprated to 400 kV operation. This would increase the capacity of boundary NW2 to 4 GW. Re-inforcement of the 132 kV network would be necessary to secure demand. Following the uprating of the second circuit to 400V, the capability of boundary NW2 is now limited by the rating of cables in the Pentir - Trawsfynydd double circuit. Increasing the capacity of these cables would further increase the boundary capability of NW2 to 6 GW.

130. Boundary NW3 (shown in green) is comprised of two double circuits and has a capacity of 3.7 GW. The capacity could be increased to 6.5 GW by reconductoring the lower rated double circuit between Trawsfynydd and Deeside.

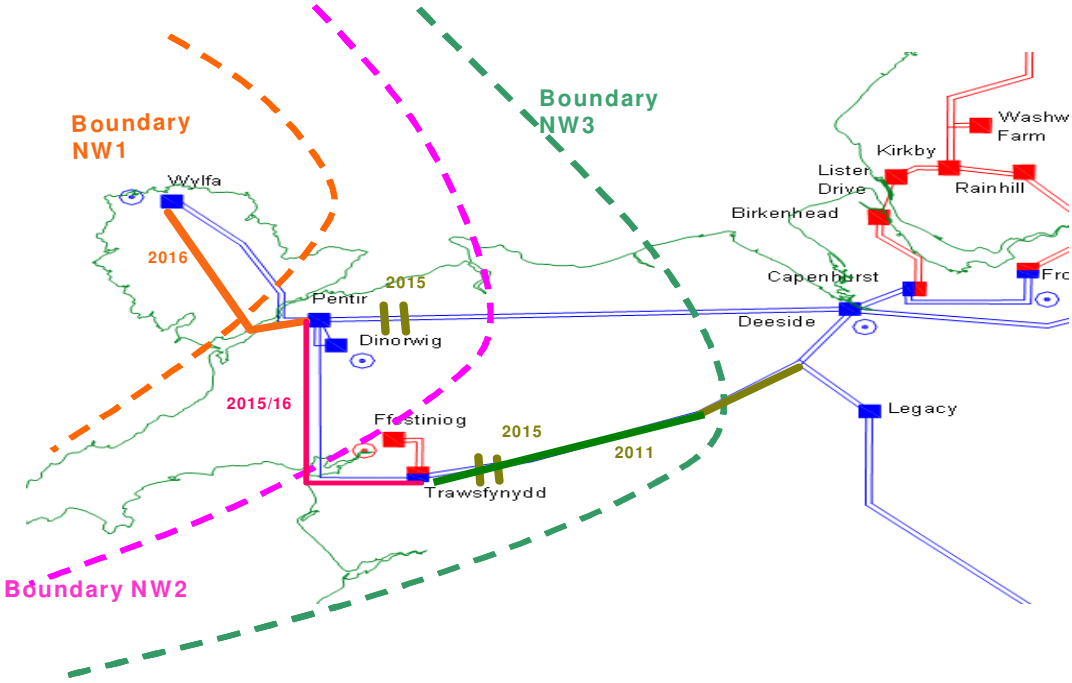
131. Existing transient stability issues in the North Wales group would be exacerbated by the increase in generation, and series compensation is required in the Pentir-Deeside and Trawsfynydd-Deeside circuits to reduce the impedance and improve stability. It is likely that the combination of a HVDC link into Deeside, the interconnector into Pentir and the introduction of series compensation would give rise the other electromagnetic concerns such as negative phase sequences and harmonic distortion. These would need to be addressed and resolved. This detailed analysis has yet to be undertaken, but it is considered that a suitable solution to these is feasible.

Table 6.3: Capacity provided by proposed re-inforcements

	Network Boundary	Existing Network Capacity	2010/16	2017/18	2018/19	2019/20	2020/21	2021+
Forecast generation		3 GW (existing generation)	3GW[1]	3.5(4.5)[2]GW	4.5(6.0)GW	5.0(6.5)GW	5.5(7.5)GW	8.5(10.5)GW
Generation which can be accommodate in zone	Boundary NW1	1.32GW	1.32GW	4.65GW	4.65GW	4.65GW	4.65GW	4.65GW
	Boundary NW2	3.0GW	4GW	6GW	6GW	6GW	6GW	6GW
	Boundary NW 3	3.7GW	6.5GW	6.5GW	6.5GW	6.5GW	6.6GW	6.5GW

White background: Current capacity
Blue background: Capacity with reinforcements
Red background: Failure to meet GB SQSS criteria post reinforcement

Figure 6.4: North Wales network post reinforcement



Approach to undertaking the reinforcements

132. Within boundary NW3, to accommodate the generation scenario, the conductors on the Trawsfynydd – Deeside circuit need to be replaced to provide a higher capacity by 2016/17. However, the equipment that attaches the conductors to the towers, and also insulates the conductors from the towers (known as fittings) on this circuit are in a poor condition

and to ensure the continued reliability of the circuit, are due to be replaced in 2011. To replace the fittings, the overhead line will need to be taken out of service and works undertaken at each tower along the route. Considerable cost savings can be achieved by increasing the conductor capacity at the same time rather than revisiting the circuit again in 2016/17 and repeating much of the work.

133. Within boundary NW2, the rating of the existing cables across the Glaslyn estuary in the Pentir-Trawsfynydd circuit limit the capability of the boundary below that of the overhead line rating. However, the capacity of the cable sections can be increased to match the overhead rating by laying additional cores in parallel with the existing cables. It is proposed to defer this work until a firm need to accommodate the power flows has been identified.

134. It is assumed the proposed additional double circuit from Wylfa to Pentir would take approximately seven years to complete, four of these being needed to acquire consents. To secure the overall programme of works the activities to gain consents for this new line should commence immediately but commitment to construction should be deferred until the generation at Wylfa exceeds 2GW.

Table 6.4: Programme of work

Key Activities	Wylfa-Pentir	Pentir-Trawsfynydd	Trawsfynydd-Deeside
2009	Routing studies, environmental assessment, designs	Engage Manweb Commence planning permission designs	Revise Existing asset replacement scheme. Locate / Design Series compensation
2010	Consult/ Environmental assessment	Consult/ Environmental assessment.	Restringing. Prepare Planning applications etc.
2011	Submit application -IPC assessment/	Obtain Planning Permission	Restringing . Apply for Permissions/ consent
2012	Obtain Consent - order materials	Site works commence: Pentir, Manweb, Trawsfynydd etc.	Obtain Consent, Series compensation
2013	Site access arrangements	Provide supply to Manweb to vacate route	Site Works
2014	Foundations	Install cables	Installation
2015	Structures / Stringing	Commission new circuit	Divert connections to Series compensation-energise
2016	Commission		

Estimated Costs of the Reinforcements Identified

Table 6.5: Costs for works in North Wales

Works Scope	Estimated cost £M	Source of cost	Comments
Reconductor Trawsfynydd - Deeside, 78km route length, 2 x GAP conductor	66	Generic cost £/km agreed with asset investment and construction	Assumes 'normal' site conditions/access
Series Compensation 120 MVAr installation	25	IP1 estimate plus budget figures from ABB (see Scottish)	Assumes line entry in line with route and no major deviations
Second circuit Pentir-Trawsfynydd	155	Scheme Sanction for Imera at Pentir - scope	
New Line Wylfa- Pentir. 400 kV 35km 3x700 sq. mm.	95	EDF scheme for connection at Wylfa Wylfa costs=£4.5M - doubled for 2 bays. New overhead line 35kM Generic cost @£2M/ km due to local terrain. Pentir costs for EdF connection =£13.2M plus £6M (ip1 estimate) for second circuit plus cable entry, less £3.5M for Pentir costs already in second circuit costs above	Crossing of Menai Straits - area of concern. Assumes re-use of redundant Wylfa generator bays.
TOTAL COST	**£341M**		

Conclusions for North Wales

135. The transmission capacity in North Wales is almost fully utilised at present with limited opportunity to connect up to 300 MW on Anglesey. The contracted 500 MW interconnector from Ireland to Pentir for full output in 2015 triggers the need for the second Pentir and Trawsfynydd 400 kV circuit.

136. It has been assumed that Wylfa nuclear power station will commence decommissioning from 2010 onwards thus releasing around 1 GW of capacity, with subsequent replanting not anticipated prior to 2020. The closure of the nuclear power station reduces the transient stability of the network in North Wales and as such the reinforcement between Pentir and Trawsfynydd is required to restore stability limits prior to accommodating the interconnector to Ireland.

137. It is assumed that between 3 GW and 4.5 GW of offshore wind will seek connection to the onshore transmission system in the North West of England between 2015 and 2020. The anticipated closure of Wylfa nuclear power station will release capacity for the first 1000 MW of wind to connect to the Wylfa substation via AC cables, and changes to the GB SQSS may result in Wylfa accommodating 1.8 GW of generation without further onshore reinforcement. The second Pentir – Trawsfynydd circuit is required for:

- Offshore wind in excess of 1.8 GW (Gwynt-y-Môr already committed at 735 MW), or
- Construction of the interconnector to Ireland, or
- Replanting of the nuclear power station (new unit assumed 1.67 GW);
- A CCGT station together with offshore wind farms.

138. When the total generation connecting to the North Wales group exceeds 3.7 GW the Trawsfynydd-Deeside circuits need to be reconductored and series compensation installed to maintain stability.

139. The total cost of the works is estimated to be £340M and could be commissioned by 2016/17. On completion, in the region of 6.5 GW of generation could be accommodated, with the reinforcements sufficiently flexible to accommodate a mix of wind, nuclear, pumped storage and conventional plant. To ensure the programme can be met and additional constraint costs are not incurred, some of the engineering and consents works must commence early in 2009, with commitment to construction between 2010 for the Trawsfynydd – Deeside circuits, and 2012 for the Wylfa - Pentir and Pentir - Trawsfynydd circuits.

Chapter 7 - Central Wales

140. The Welsh Assembly Government Technical Advice Note 8[13] (TAN 8) identifies a target onshore wind generation target of 800 MW. The majority of wind resource is in central Wales which has no immediate connection to the main interconnected transmission system.

141. New transmission assets including overhead line and cable sections need to be commissioned in order to connect the new generation to the transmission network. As the generation is made up of a number of small to medium wind farms, the current proposal is to create a hub substation to which all wind farms input. A single transmission route will then be used to connect to the transmission network in the Legacy-Shrewsbury-Ironbridge circuits. Exact locations of both substation and transmission connection point are being evaluated.

142. The potential for significant new generation in the north of Wales and the resulting pressure on boundary NW3 as detailed above has highlighted an opportunity for considering a strategic development in central Wales. The typical load factor for wind generation is in the region of 30%. Therefore the capacity of the connection to the main interconnected system will frequently be under-utilised. An additional connection from the Trawsfynydd area to the new substation in central Wales would allow full utilisation of this circuit and provide additional capacity on the NW3 boundary. Furthermore by connecting further south than the Legacy-Shrewsbury-Ironbridge circuit, for example, Ironbridge or Bishop's Wood substations, additional relief on heavily loaded circuits will be realised, see Figure 7.1 below. Exploration of the transmission technology used is critical to making full strategic use of this new through route.

[13] http://wales.gov.uk/topics/planning/policy/tans/tan8/?lang=en&ts=1

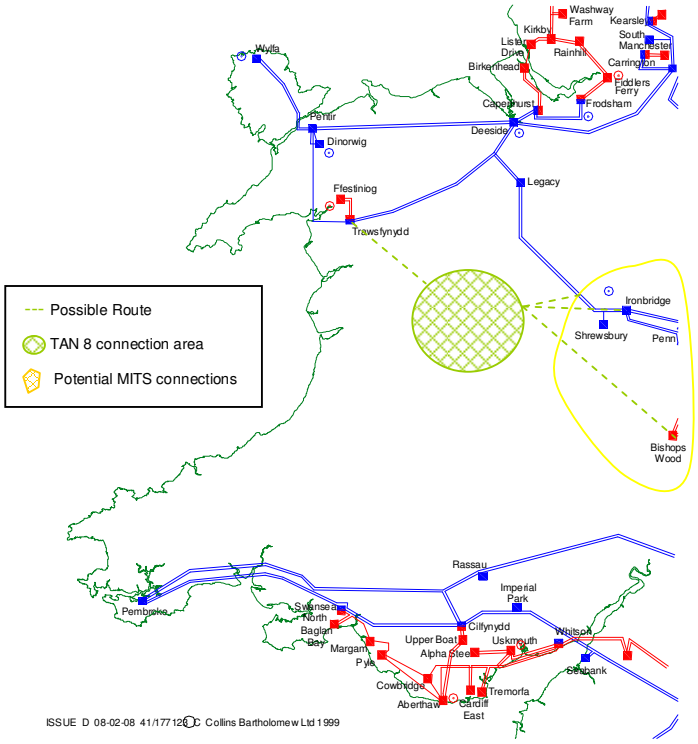


Figure 7.1: Central Wales Connection Development

Chapter 8 - East Coast of England

143. The onshore transmission system on the East Coast of England spans from the predominately 275 kV system around the Teesside area down through two 400 kV double circuits into the Humber area before continuing further down through four 400 kV double circuits towards the major load centre of London. Before reaching London the most easterly of these four double circuits branches out into a further two 400 kV double circuits forming a ring around East Anglia. This is illustrated in Figure 8.1 below.

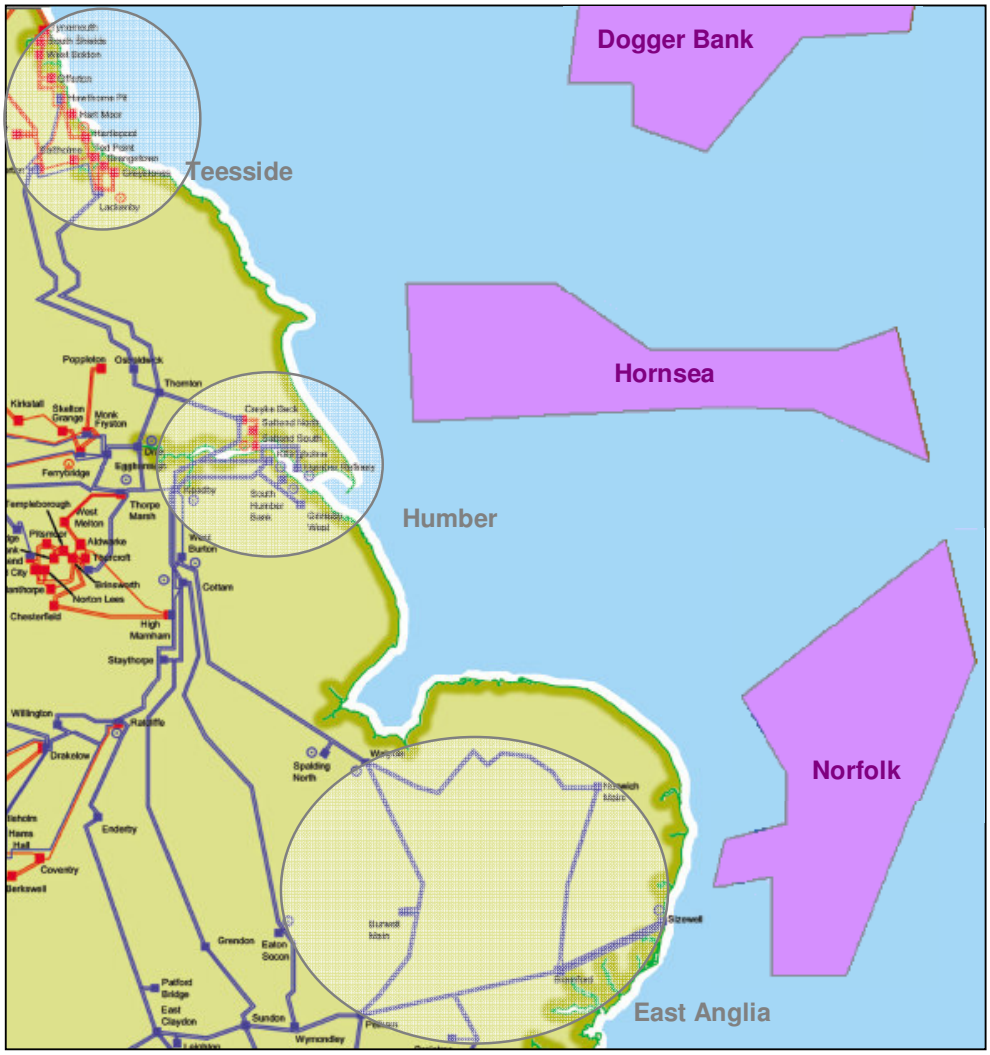


Figure 8.1: East Coast Transmission System and Indicative Offshore Wind Zones

144. Consistent with the remainder of the transmission system in Great Britain, the capacity and topography of the network within and interconnecting these areas have developed against the volume and spatial disposition of the conventional generation and demand currently connected to the system. The scenarios and sensitivities investigated

suggest a significant shift away from these fundamental, defining characteristics in terms of generation.

145. In Great Britain we have been fortunate enough that the North Sea has allowed almost complete independence in terms of domestic energy requirements over the last 30 years. As the fossil fuel sources of energy from this region are dwindling, new sources of energy are required in order to maintain security of supply. This situation presents an opportunity to decarbonise a large proportion of the fuel sources used across Great Britain in an attempt to slow the progress of climate change across the globe. For the electricity industry, this represents a major challenge and will require levels of investment not seen since the inception of the high voltage transmission system some 40 years ago. Luckily, in moving towards this new era of a low carbon economy, the North Sea will continue to play a vital role in providing energy to British industries and households. Through the combination of large areas of water depths suitable for the piling of turbine foundations and significant wind speeds available for conversion into electricity, the North Sea's continued prominent role in the future provision of Britain's energy needs is incontrovertible.

146. As previously outlined, wind turbine technology is by far the most mature method for the generation of electricity from renewable sources that is capable of being scaled up sufficiently in order to meet 2020 targets. Therefore, the generation scenarios and sensitivities investigated for the east coast area of the transmission system in England and Wales include large amounts of offshore wind generation consistent with the plausible scenarios for meeting renewable targets in 2020 and maintaining the 'flight path' towards carbon emission reduction targets in 2050. The level of offshore wind generation that will materialise before 2020 is dependant on both the levels of onshore wind generation assumed to be available to contribute to the 36% of electricity assumed to come from renewables and the finalisation of the details for the 15% all energy EU target for GB[14]. It is both the volume and spatial disposition of this offshore wind generation along with new gas fired generation developments, possible nuclear rebuild and future CCS projects across these areas that drives the need for significant reinforcement of the transmission system.

147. In addition to the many projects currently under development out of the Round 2 offshore wind leasing process, The Crown Estate has identified three indicative zones in the North Sea off the east coast of England with the potential for economic development in the Third Round of wind leasing. These zones are identified above, in Figure 8.1, as Dogger Bank, Hornsea and Norfolk.

[14]The contribution electricity will have to make towards the overall energy target for 2020 could vary depending on the treatment of aviation and electric transport as well as the impact of trading. Given the level of scrutiny given to the scenarios agreed and their consistency with others produced independently, the 36% assumed is considered a reasonable assumption.

148. The nearest feasible landing points for power from Dogger Bank and Hornsea are the South Durham coast, the Yorkshire coast to the south of Bridlington, and the Lincolnshire coast. Onshore transmission development in the North Yorkshire Moors National Park, in the Yorkshire Wolds or in the coastal area between Scarborough and Bridlington is likely to be particularly contentious, so is not considered in this analysis.

149. For reasons discussed below, the preferred areas for connection are the coasts of Yorkshire and/or Lincolnshire. The layout and function of the 400 kV onshore network in this area can best be considered by describing it in three sections.

Characteristics of Onshore Transmission Network – Humberside

150. The first is a 'central spine', running from Creyke Beck substation near Hull, south to Keadby near Scunthorpe and then following the Trent south to the power stations at West Burton, Cottam and Ratcliffe. This section of network carries north-south transfers from Scotland and North East England together with output from power stations on the Humber, gathers the output of power stations on the Trent and links to the circuits supplying the London and West Midlands conurbations.

151. The second is an eastern loop which consists of two 400 kV lines running from Keadby towards Killingholme, with one line continuing towards Grimsby. These lines gather the outputs of power stations on the south side of the Humber and feed it into the main system at Keadby.

152. Finally, the western section interconnects the existing large coal-fired power stations at Drax, Eggborough and Ferrybridge. This part of the network also supplies the demand centres of West Yorkshire and the Sheffield area, and interconnects with the 400 kV system in Lancashire and Cheshire.

153. Two 400 kV lines run from the north of the area towards the Teesside area in the North East, while four lines run south to the Midlands, East Anglia and the South East. Given the disposition of generating plant in the GB system, the predominant pattern of power flows is from North to South and consequently this part of the network can often be heavily stressed.

154. Against the scenarios and sensitivities considered, transfers from the North are such that the North East to Yorkshire lines may require uprating to carry the power from onshore and Rounds 1 & 2 offshore wind, together with conventional generation in Scotland and the North East. Any further generation connected in the Teesside area, including further offshore wind generation, would likely trigger a requirement for one or more additional lines to Yorkshire. Delays and difficulties in gaining consents for these circuits can be expected. Given the interaction between the factors outlined above and the likelihood of such an

overhead line being required, the Teesside area was considered an unattractive option for connecting further offshore wind developments.

155. Therefore, a total of up to 12 GW of Round 3 offshore wind generation capacity from the Dogger Bank and Hornsea zones is assumed to connect into the Humber region and share onshore transmission system capacity with conventional plant and Round 2 wind projects. A summary of the possible developments in generation connected to Humberside is provided in Table 8.1, below. Of the 12 GW of Round 3 offshore wind potential in this region, only 3 to 4 GW is assumed to contribute towards 2020 targets.

Table 8.1: New Generating Plant in Humber Region

Plant	Capacity	Status	Connection Site
R3 Wind Farms (Dogger Bank)	Up to 9 GW (agreed scenario ~ 1 to 6 GW)	Proposed	Creyke Beck, Keadby, Killingholme
R3 Wind Farms (Hornsea)	Up to 3 GW (agreed scenario ~ 2 to 3GW)	Proposed	Killingholme, Grimsby West OR tee into HVDC link
R2 Wind Farms Westernmost Rough Humber Gateway	 240 MW 300 MW	 Proposed Contracted	 Grimsby West
CCGT Immingham 2 Killingholme 2	 600 MW 600 MW	 Contracted Contracted	 Grimsby West Killingholme

156. Along with increased North to South power transfers across this area of the network, the connection of offshore wind generation is one of the main drivers for reinforcement requirements in this region. Various options for the connection of this generation were investigated.

Offshore Wind Connection Options and Issues – Humberside

157. The Round 3 offshore wind generation locations in the Dogger Bank and Hornsea are positioned such that HVDC cables are considered to be the most practical and economic connection option given current and/or foreseeable technology. These connections, currently limited to ~1.1 GW each, will normally be terminated in converter stations onshore.

158. One option for connecting offshore wind generation is to bring cables ashore to coastal substations (existing or newly-built) and reinforce the 400 kV, AC network as necessary. A second option is to extend the HVDC cables further inland to existing substations and reinforce the 400 kV, AC network local to these connection points as necessary. The estimated costs of the HVDC cables are such that either solution may be economic, depending on the local circumstances. The optimum arrangement in terms of connection points turns out to be a hybrid of the above two approaches. This is illustrated in Figure 8.2, below.

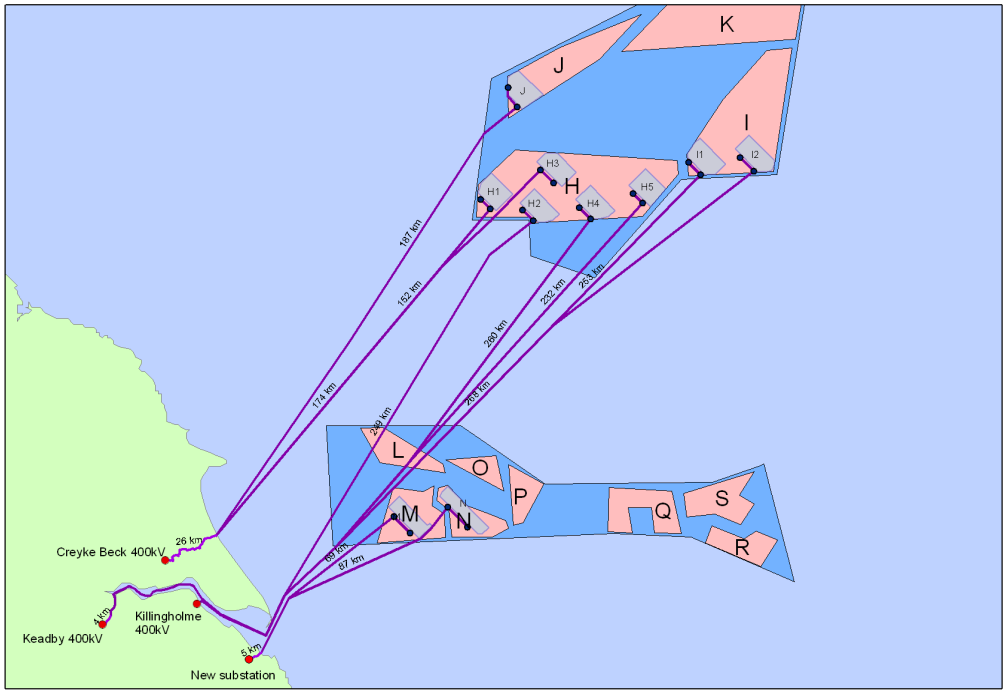


Figure 8.2: Round 3 Wind Farm Connection Options – Humber
(From "Round 3 Offshore Wind Farm Connection Study", published by The Crown Estate)

159. As described, the most economic and practical connection points for Dogger Bank wind farms are in Yorkshire and North Lincolnshire, in a central part of the 400 kV onshore transmission system (both Options 1 and 2 refer, below). Reinforcement requirements in this area, and over a wider area of the system will be driven by the Round 3 wind generation but also by the output of existing and potential conventional generation in Yorkshire and Lincolnshire, power transfers from the North East of England, due to conventional generation developments, and power transfers from Scotland due in part to onshore and offshore wind generation.

160. In exploring the two approaches to system development outlined above, three options for the connection of offshore wind generation and reinforcing the onshore transmission system were identified. These are outlined in Table 8.2 below.

Table 8.2: Options for Connection of Dogger Bank and Hornsea Offshore Wind							
Option		**Offshore Zone**	**Offshore Cost (£M)**	**Onshore Works**	**Onshore Cost (£M)**	**Total (£M)**	**Comments**
1a (AC)	Connection to inland substations	1.1 GW HVDC links from Dogger Bank and/or Hornsea	3700	New 400 kV line between Willington and Chesterfield Major substation extensions	360	4060	Major consent risk for both onshore OHL, offshore cables on land and substation extensions
1b (AC)	Connection to coastal substations	1.1 GW HVDC links from Dogger Bank and/or Hornsea	3600	New 400 kV OHL between Grimsby West and Walpole and Walpole to a new substation north of Eaton Socon	450	4050	Major consent risk for both onshore OHL, offshore cables on land and substation extensions
2 (DC)	Connection to coastal substations and direct tee into new HVDC link between a new South Killingholme and Walpole substations	1.1 GW HVDC links from Dogger Bank and/or Hornsea	3200	New HVDC cable circuit between a new substation south of Killingholme and Walpole substation Quad Boosters on the Walpole to Norwich circuit.	360	3560	Significant reduction in consent risks Reduction in Costs due to HVDC converter savings

161. From the table above, the DC reinforcement option (Option 2) is the best solution overall for the connection of Round 3 offshore wind generation from the Dogger Bank and Hornsea offshore zones given the assumptions utilised. This particular reinforcement is assessed further later in this section in the context of the entire east coast portion of the transmission system as a whole, where the additional wider system benefits of this option are discussed.

Characteristics of Onshore Transmission Network – East Anglia

162. The onshore, 400 kV transmission system in this part of the country is characterised by a double circuit ring that links Walpole, Norwich, Bramford, Pelham and Burwell substations. This double circuit ring serves the demand centres of King's Lynn, Norwich, Ipswich, Bishop's Stortford and Cambridge respectively. Four circuits (approximately 43 km

route length) run towards the coast from Bramford substation to Sizewell, forming an overhead line radial spur. This spur provides a transmission corridor for the existing pressurised water reactor (PWR) nuclear generator located at Sizewell. The scenarios and sensitivities investigated also include the Round 2 offshore wind farm, Greater Gabbard, at Sizewell.

163. One double circuit 400 kV line runs north from Walpole towards Cottam and West Burton linking into the 'central spine' of the transmission system described above for the Humber region. As such, this part of the transmission system carries power transfers from generation in the North East of England.

164. At the bottom of the East Anglia loop there is a circuit route between Pelham, Bramford and Rayleigh Main that is a corridor for generation from the power stations at Walpole, Norwich and Sizewell, carrying it further south towards Essex and Kent.

165. Pelham substation provides additional interconnection between the East Anglia region and other sections of the transmission system. Two 400 kV lines run west from Pelham to supply demand centres in west Hertfordshire and another two 400kV lines run south extending the transmission system to the outskirts of Greater London.

166. The Round 2 offshore wind and CCGT developments already contracted in this region and forming part of the agreed scenarios are such that some of the existing onshore transmission overhead lines already require uprating. Given that the nearest landing points for Round 3 offshore wind generation in the Norfolk offshore zone, are in the East Anglia area it follows that the connection of this generation or nuclear replanting at Sizewell would likely require further reinforcement.

167. A summary of the possible developments in generation connected to East Anglia is provided in Table 8.3, below.

Table 8.3: New Generating Plant in East Anglia Region

Plant	Capacity	Status	Connection Site
Nuclear	3.3 GW (2 x 1.65 GW units)	Contracted	Sizewell
R3 Wind Farms (Norfolk)	Up to 5 GW (agreed scenario = 3 to 4 GW)	Proposed	Sizewell
R2 Wind Farms			
Triton Knoll	1200 MW	Proposed	Bicker Fen
Lincs	250 MW	Contracted	Walpole
Docking Shoal	500 MW	Contracted	Walpole
Race Bank	500 MW	Contracted	Walpole
Sheringham Shoal	315 MW	Contracted	Norwich
Dudgeon East	300 MW	Proposed	Norwich
Greater Gabbard	500 MW	Contracted	Sizewell
CCGT			
Sutton Bridge B	1205 MW	Contracted	Walpole

168. Along with general power transfers down into the south east and London across this area of the network, the connection of further CCGT generation and the potential for nuclear replanting at Sizewell, the connection of offshore wind generation is one of the main drivers for reinforcement requirements in this region. Given its location offshore, the economic options for the connection of offshore wind generation in the Norfolk zone are limited.

Offshore Wind Connection Options and Issues – East Anglia

169. For the Norfolk offshore zone, either AC and/or HVDC cables could be the most economic technology for the connection of offshore wind generation. It is likely that both technologies will be utilised in connecting different parts of this offshore zone to the onshore transmission system in East Anglia. The nearest onshore substations geographically are Norwich Main and Sizewell.

170. The option of connecting offshore wind generation to new coastal substations has not been investigated in detail. Any new coastal substation would require additional overhead lines to connect it to the existing onshore transmission system, which generally come with difficulties in gaining the necessary consents. In addition, extending the transmission system to the coast does not negate the requirement for further reinforcement out of the East Anglia region to the rest of the interconnected system. Therefore the connection options described below will focus on bringing AC or HVDC cables to existing onshore substations. However, this would not rule out more detailed investigations into the possibility of adopting existing 132 kV distribution network routes to the coast, such as that stretching from Norwich Main out to the coast near Great Yarmouth, if these were discovered to be the overall most economic and efficient solution in future.

171. The potential connection points for the Norfolk zone are illustrated in Figure 8.3, below.

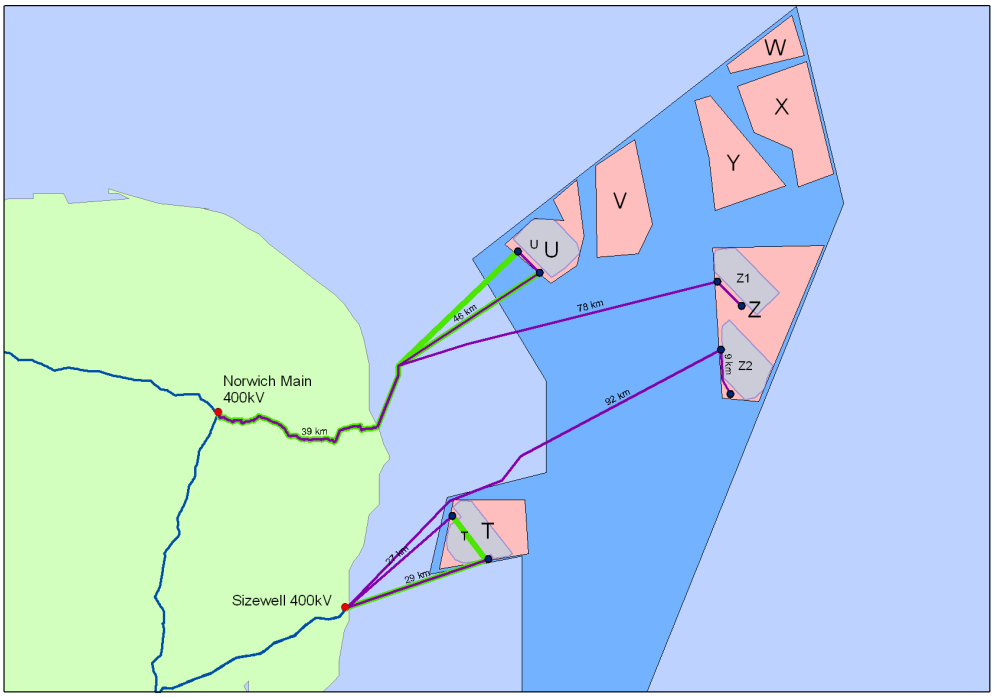


Figure 8.3: Round 3 Wind Farm Connection Options – East Anglia
(From "Round 3 Offshore Wind Farm Connection Study", published by The Crown Estate)

172. As previously outlined, Sizewell is a connection point for an existing PWR nuclear generator. Currently a connection agreement is in place for the connection of new European Pressurised Water Reactor (EPR) nuclear generators at Sizewell as staged connections in 2016 and 2021. The capacity of these units would be in addition to the existing unit, which is not scheduled to decommission until 2035[15]. As mentioned above, the SSI and SEA for the next fleet of nuclear generators are yet to be completed, but this does not preclude the construction of reactors within similar timescales to the Round 3 offshore wind developments once it is complete. Although no formal decision on new nuclear at Sizewell has been taken the likelihood of its development is as likely as any other existing nuclear site.

173. As nuclear generation has an extremely low marginal cost of generating, it is normally run as 'base load' plant. Although wind generation is generally assumed to share a significant amount of transmission system capacity with conventional plant, this will occur to a lesser extent in areas of the system where wind shares with nuclear generation.

174. The closest onshore connection points for the assumed locations of Norfolk offshore wind generation developments are Norwich and Sizewell substations. Walpole and Raleigh are further potential onshore connection points. However, both are a considerable offshore distance

[15] http://www.british-energy.com/pagetemplate.php?pid=96

from where Round 3 offshore generation developments are assumed to be located in this region. In addition, the Wash is heavily environmentally designated. It is for these reasons that connection to Walpole and Raleigh are relatively less attractive than the other sites investigated at this stage.

Table 8.4: Options for Connection of Norfolk Offshore Wind

Option		Offshore Zone	Offshore Cost (£M)	Onshore Works	Onshore Cost (£M)	Total (£M)	Comments
1	Maximum wind into substations closest to shore in East Anglia	Norfolk	1520	Reconductor of Walpole to Norwich and Norwich to Bramford double circuits, New Bramford 400 kV substation New 400 kV Bramford to Twinstead double circuit OHL to create a Pelham-Bramford double circuit route and Bramford-Braintree-Rayleigh OHL	210	1730	Connection into both Norwich and/or Sizewell possible Between 3 and 4 GW of offshore wind expected (dependent on Scottish onshore wind)

175. Compared to the connection options for other Round 3 offshore wind development zones, the options available for connection into the onshore transmission system in East Anglia are limited. The overall most economic and efficient solution is the connection of the maximum amount of wind possible into Sizewell along with key upgrades to the onshore transmission that will facilitate these new offshore wind generation connections and/or nuclear replanting at Sizewell. These reinforcements are assessed below in the context of the entire east coast portion of the transmission system as a whole.

Overall East Coast Onshore Transmission Considerations

176. To determine the generation capacity (existing and new) that the transmission system in the key regions of Humber and East Anglia on the east coast of England can accommodate, the onshore network is investigated against the criteria outlined in GB SQSS. It is assumed that the reader is familiar with these criteria, which at a simplistic level ensure the system is planned so that sufficient capacity is available following a credible contingency (or secured event; generally N – 2) as well as limiting the loss of power infeed resulting from contingencies. The minimum, deterministic, security criteria in the GB SQSS have been applied across six key boundaries, the characteristics of which are shown in Figure 8.4 and detailed in Table 8.5 below.

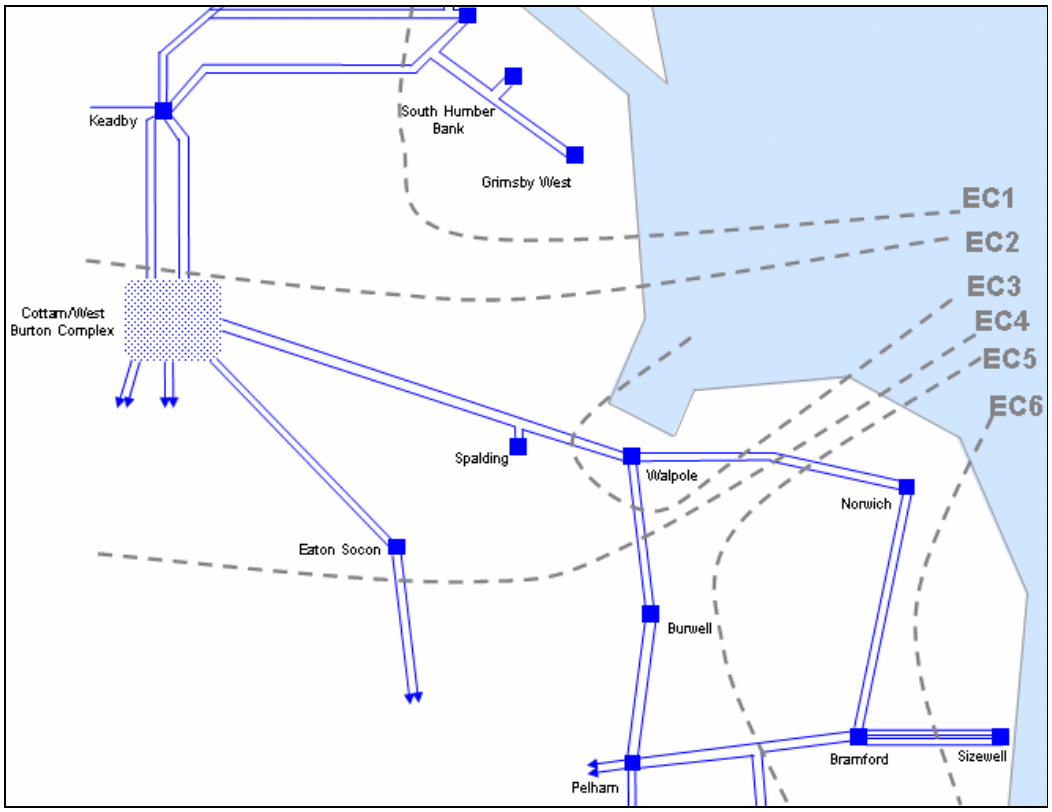
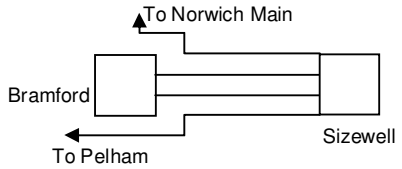


Figure 8.4: Transmission analysis boundaries considered on the east coast

Table 8.5: East Coast Transmission Boundary Characteristics			
Boundary	**Type**	**Characteristics**	**Existing Capacity (MW)**
EC 1	Local	In the case of EC1, the remaining circuit capacity (plus the minimum demand level of ~700 MW) for the worst case contingency, would allow 6 GW of generation to connect within the area of the system bound by these circuits. The capability of EC1 is directly limited by the amount of generation situated within it, which makes it a 'local' boundary. On such 'local' boundaries general system power flows have less of an impact. With approximately 4.7 GW of generation currently connected and a total of 5.1 GW contracted in this area, less than 1 GW could be accommodated without the need for major reinforcements.	6 000
EC 2	Wider System	The EC 2 boundary is equivalent to the SYS 'North to Midlands' (B8) boundary that stretches across the entire width of England. Therefore, the capability of this boundary is affected by generation in the Humber area, but also by the general North – South power flows on the system. As with EC 1, the capacity of EC 2 is planned against a range of credible, N – 2 contingencies.	11 000

		On the East Coast side of this boundary, there are four, 400 kV double circuit, north – south routes crossing this boundary (as well as additional 275 kV east – west circuits). Traditionally it has been difficult to persuade these four double circuits (with FACTS devices for example) to share the loading on this part of the system equally whilst minimising fault levels at local substations. The analysis undertaken for this work assumes that the planned reconfiguration work around Cottam has completed to better facilitate this 'sharing' and therefore better utilise existing capacity. New offshore wind generation connections, interacting with conventional gas and coal plant in the Humber region together with an increased North – South flow on the system lead to limits across this boundary in future years as large amounts of the electricity generated in the North makes its way towards the majority of the demand located in the South.	
EC 3	Local	EC 3 is a boundary surrounding the increasingly critical site of Walpole by the Wash. This is considered a 'local' boundary and is heavily affected by the amount of generation connected at Walpole (currently contracted as ~3.4 GW). However, power flows on the most easterly North – South double circuit from West Burton exacerbate the constraints on the two congested double circuits to the south of Walpole. This is particularly the case on the Norwich Main – Walpole and Bramford – Norwich routes which are already in need of uprating as a result of new CCGT and Round 2 wind generation contracted to connect.	3 000
EC 4	Wider System	EC 4 is close to, but slightly further south than the 'Midlands to South' SYS boundary. The positioning of this boundary seeks to capture the capability of all 4 double circuits' overhead line routes south of West Burton after the most easterly circuit splits into two south of Walpole (creating a total of 6 double circuits). As with EC 2, above, the capability of EC 4 will be impacted not only by generation connected to the adjacent circuits in the network but also by the general North – South flow on the system. Specific local generation that will have an impact on this boundary is CCGT, Round 2 and Round 3 offshore wind as well as existing and potential new nuclear generation in East Anglia.	14 000
EC 5	Local	EC 5 is a 'local' boundary, bound by the Norwich Main – Walpole and Bramford – Pelham + Bramford – Braintree double circuits. For the N – 2 contingency of either of these double circuits, all generation connected within this boundary must be carried on the remaining double circuit. Not including the potential for nuclear build and Round 3 offshore wind, this is already ~ 3 GW. Therefore, to accommodate any new CCGT, Round 3 offshore wind and/or new nuclear build at Sizewell and or Norwich Main, further capacity across this boundary is required.	3 000

EC 6	Local	The EC 6 boundary intersects the two double circuits stretching from Bramford to Sizewell. Currently one of these circuits connects Sizewell directly to Norwich Main, one connects Sizewell directly to Pelham and two connect straight into Bramford.  This circuit configuration currently limits the amount of generation that can be connected at Sizewell.	2 500

Assessment of Boundary Capabilities and Reinforcement Requirements

177. Having described the characteristics of each boundary investigated as part of the East Coast area, boundary capabilities and associated reinforcement requirements are outlined below.

178. **EC1** – The analysis of the Humber area, above, indicates that this part of the network is the most economic and efficient for the connection of R3 offshore wind generation from the Dogger Bank and Hornsea. Although a potential of up to 12 GW has been identified for these areas in other publications[16], the agreed scenario assumes that only between 4 and 8 GW will materialise before 2020 (depending on the level of onshore wind in Scotland).

179. Given the remaining capacity of ~ 1 GW across this boundary outlined in the table above, system reinforcement is required to accommodate any Round 3 wind generation and/or other conventional plant over and above this level. It is possible to connect some of the wind further inland. However, this would increase the cost of offshore/onshore cabling required somewhat and would not negate the requirement to reinforce boundary EC2, below.

180. To address this, it is proposed to establish an onshore, multi-terminal, VSC – HVDC link between the local transmission network south of the Humber and the existing Walpole substation compound by the Wash. The preferred connection point in the Humber area would be a new substation to the south of the existing Killingholme site, illustrated in Figure 8.5. A connection into this site would provide two double circuit connections to the remainder of the system.

[16] "Round 3 Connection Study", published by The Crown Estate on 18 December 2008

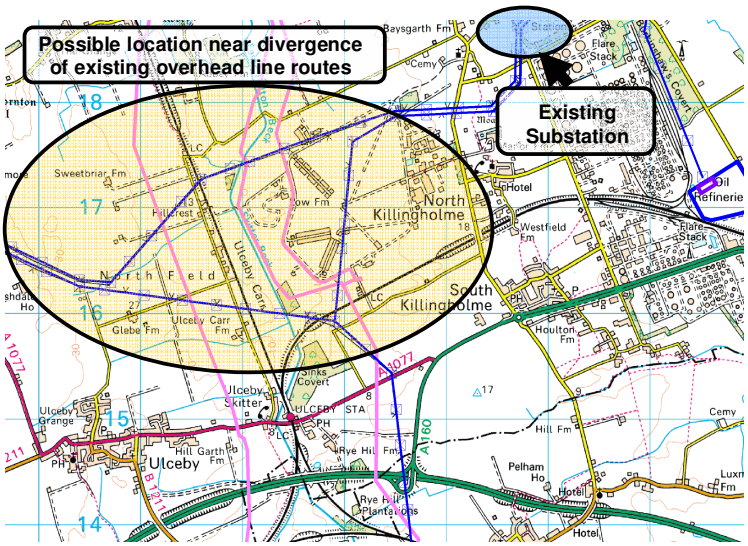


Figure 8.5 – Possible location for new substation (full siting study required)

181. This link, of approximately 2 GW capacity, would provide further capacity out of this area, but could also provide the potential to tee in a limited amount of offshore wind generation thereby offering a potential saving in offshore transmission costs. In addition, further benefits are achieved from the controllability of such a link, delaying reinforcement requirements for certain contingencies in the East Anglia region. Part of the detailed design work will involve working with manufacturers to consider all the technical issues and limitations and design out any potential problems at an early stage.

182. **EC2** – With quite a large percentage of the total generation installed in Great Britain and a much smaller percentage of total demand located north of EC2, a significant north to south flow occurs across this boundary. As the volumes of onshore and offshore wind capacity to the north of this boundary increase rapidly out to 2020, invariably displacing some conventional plant to the south, the EC2 boundary becomes more heavily stressed. Against all scenarios the trend of power flows across this boundary increase out to 2015 at which point there is a short respite in growth due to large conventional plant that have opted out of the LCPD closing. However, growth quickly picks up again as 2020 targets loom ever closer and wind generation volumes increase at a significant rate in parallel with the replanting of conventional plant.

183. The VSC – HVDC link proposed for the reinforcement of EC1 has the added benefit of providing an additional EC2 capacity roughly equal to the installed capacity of the link (currently estimated at around 2 GW). It is proposed to undertake the detailed planning work that will facilitate the connection of such a link by around 2017. This would allow conventional

and wind projects north of the boundary to proceed, provide additional benefits in East Anglia (although not without further reinforcement in that area) and potentially allow some early Round 3 offshore wind projects to tee into the link reducing the cost of their connection.

184. **EC3** – Walpole substation, which is the proposed connection site for several Round 2 projects and a significant amount of gas-fired generation, is currently near its maximum capacity. Many of the reinforcements proposed for other boundaries also increase the capability of EC3 and hence the potential for connection into Walpole. The reconductoring of circuits between Walpole, Norwich Main and Bramford could begin to increase capacity as early as 2013. This increase is sufficient to allow some of the proposed generation projects to connect. Further capacity is then provided by quadrature boosting transformers in the Norwich Main – Walpole circuit and the HVDC link between the Humber area and Walpole by 2017.

185. **EC4** – By establishing a link from the Humber area to Walpole further capacity is provided across EC1, EC2 and EC3 as described above. However, the majority of the extra level of power flow accommodated across this boundary will eventually have to make its way towards the major demand centre of London. In order to accommodate this flow between Walpole and the north and east of London, even before such a link is established, it is proposed to install quadrature boosting transformers in the Norwich Main – Walpole circuit. This reinforcement facilitates the necessary power flows south into London by making better use of the existing system capacity under fault outage conditions, therefore allowing the need for additional system capacity in this area to be delayed somewhat.

186. In moving beyond 2020, it may be necessary to establish a further 400 kV, double circuit route between Walpole and the Cottam – Eaton Socon overhead line route. This would further increase the capacity of EC4, redistribute the power flows into North London and provide a further outlet across EC3.

187. **EC5** – The reconductoring of Norwich Main – Walpole and Bramford – Norwich Main provides additional capacity across this boundary in the early years out to 2014. Eventually, as the amount of generation connected within this boundary increases, stability and voltage issues arise over and above the thermal issues for the N – 2 fault outage of the double circuit to the west of Bramford. This is due to the resultant significant electrical distance between the connected generation and the demand, which is located predominately in London as described above. At this point it becomes necessary to incorporate an additional section of double circuit overhead line, of approximately 35 km in length, to provide additional capacity across EC5. The proposed reinforcement provides an outlet for power under the N – 2 condition described above. In doing so, it provides the extra benefit of delaying the need for a new double

circuit overhead line between Walpole and the Cottam – Eaton Socon route to beyond 2020.

188. **EC6** – As described above, Sizewell is a geographically attractive site for the connection of Round 3 wind projects which could materialise off the east coast of East Anglia as well as a potential site for the program of new nuclear build that is planned in Great Britain. In the early years this boundary is severely limited by the circuit configuration around Bramford substation. Therefore, it is proposed to rebuild and reconfigure this site in timescales consistent with those of the projects that may materialise and in line with other proposed reinforcements, outlined above.

189. The figure below summarises the reinforcements described. The additional capacity provided is further summarised in Table 8.6.

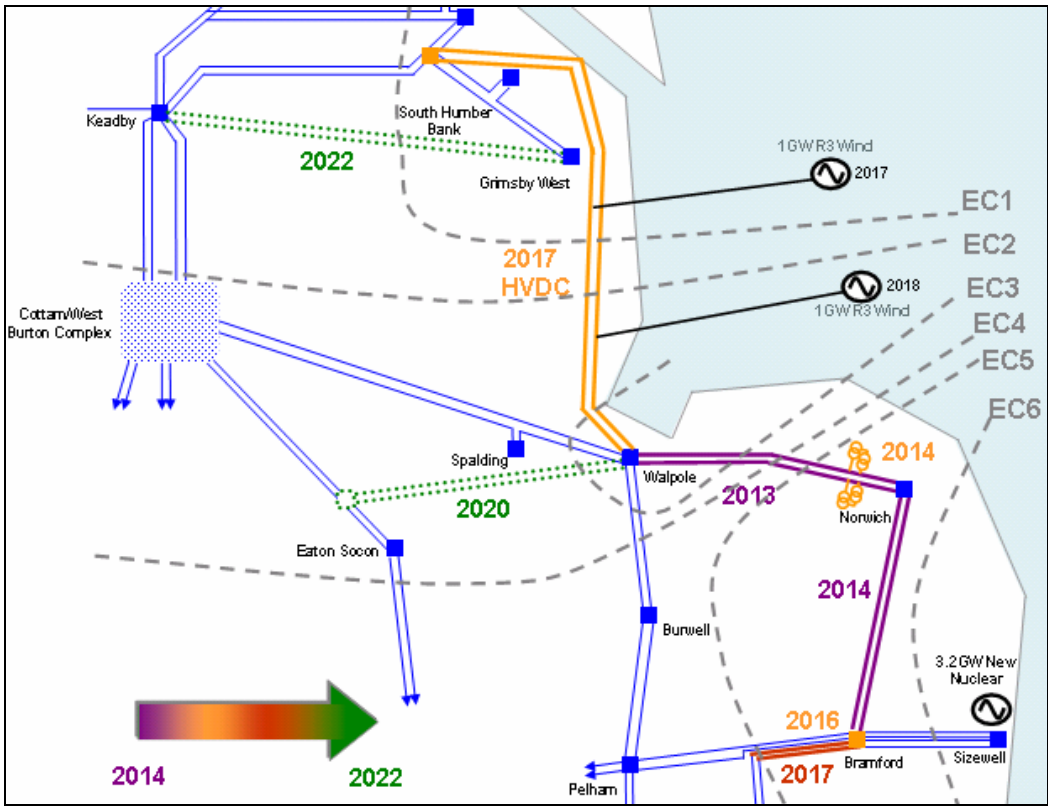


Figure 8.6: Proposed East Coast Onshore Transmission Reinforcements

190. The following table summarises the generation accommodated by the proposed reinforcements.

Table 8.6: Generation Accommodated with Strategic Reinforcement									
	Network Boundary	Existing Network Capacity (GW)	2013 (GW)	2014 (GW)	2015 (GW)	2016 (GW)	2017 (GW)	2018 (GW)	2020+ (GW)
Forecast Generation (GW)			7.3	8.5	11.7	12.5	14.5	15.3	22.3
Generation Accommodated	EC 1	6	6	6	8	8	8	8	11
	EC 2	11	11	11	13	13	13	13	14
	EC 3	3	3.5	5	6	6	6	6	10
	EC 4	14	14	16	16	16	16	16	18
	EC 5	3	3.5	5	5	5	9	9	11
	EC 6	2.5	3.5	3.5	3.5	5	8	8	8

191. The capacities highlighted in blue are those resulting from the proposed reinforcements for which detailed engineering needs to commence immediately in order to derive maximum benefit and ensure that generation projects that will contribute towards renewable targets can connect in a timely manner. Commitment to undertake these reinforcements should be taken as soon as possible to achieve this.

192. Those capacities highlighted in red are those achieved from the additional reinforcements over and above those proposed for immediate development. For these post-2020 reinforcements it is proposed to undertake detailed engineering up to the point of getting consents and only commit to build when the need case is clearer against the generation background at some point in the future.

Approach to Undertaking the Reinforcements

193. The tables below detail the yearly engineering works required to deliver the reinforcements described to the desired timescales for the Humber and East Anglia areas. Working to this program allows for the maximum benefit to be derived from these reinforcements.

Year	Table 8.7: Key Activities – East Anglia		
	Reconductoring/Quad Booster	Bramford – Twinstead route	Bramford Substation
2009	Identify sites, network studies and define scope	Routing studies identify corridor	Initiate design and integrate new line entries
2010	Environmental assessment and detailed design	Environmental assessment consultation	Civil works
2011	Planning/Consent application	Environmental assessment consultation	Installation
2012	Planning permission site access	Apply for consent	Outages – circuit change
2013	Reconductor	Obtain consent	Outages – circuit change
2014	Reconductor/Equipment installation	Access arrangements	Outages – circuit change

2015	Reconductor	Foundations	Outages – circuit change
2016	Line entries – reconductor, energise	Towers & stringing	Outages – circuit change
2017		Outages and interconnection	
2018		Outages and interconnection	

Year	Table 8.8: Key Activities – Humber		
	New substation/extension	**DC circuit**	**DC converters**
2009	Siting studies and outline design	Explore network options, constraint mapping of route and surveys	Explore technology, engage market and undertake network studies
2010	Site surveys and environmental assessment	Environmental assessments	Design, specification and tender
2011	Design and planning permission preparation	Consultation and consent preparation	Planning application, design and supplier selection
2012	Seek planning permission/consents		
2013	Obtain consent, order materials and appoint suppliers		
2014	Site Access Civil	Access/manufacture	Site access and civil works
2015	Installation	Installation	Civil works
2016	Outages and circuit changes	Installation	Transformer delivery
2017	Outages	Commission	Enter service

Estimated Costs of the Reinforcements Identified

194. The following table summarises the cost of undertaking the reinforcements identified above.

Table 8.9: Proposed East Coast Reinforcements			
Region	**Reinforcement**	**Cost (£M)**	**Comments**
Humber	New 400 kV substation and HVDC converter compound location	£60	
	VSC – HVDC converters in Humber area	£160	
	VSC – HVDC converters in Walpole area	£160	
	HVDC cable route (~130 route km)	£130	
	Total	**£510**	
East Anglia	Reconductor Walpole – Norwich Bramford Route (~140 route km)	£120	
	Walpole substation rebuild	£90	
	Bramford substation rebuild	£70	
	New 400 kV OHL between Bramford and Twinstead tee point (including circuit rearrangement; ~35 route km)	£70	
	Quadrature Boosters between Walpole and Pelham	£50	
	Total	**£400**	

Conclusions for the East Coast

195. The conclusions from this study propose to optimise both onshore and offshore transmission networks by integrating the design of these networks in order to capture significant cost savings to be achieved by connecting the earlier of the Round 3 wind farms in this region via direct tee connections into an onshore HVDC link connecting the Humber area to East Anglia.

196. In connecting these two areas, this solution affords the extra benefits of providing additional capacity for new generation connections to the north of the North to Midlands boundary as well as delaying, but not removing, the need for reinforcement in the East Anglia region.

197. In view of the novel nature of this development, pre-engineering works will be required to ensure that the solution can be developed to required timescales. Otherwise, it may be necessary to develop an alternative solution, thus negating the potential savings.

198. The cost of the onshore works required in order to achieve this is estimated to be £510M for completion by 2017.

199. Reinforcement of the network is required for either offshore wind generation and/or nuclear replanting at Sizewell in the East Anglia region. The reinforcements proposed for this area of the network include reconductoring the double circuit route from Walpole to Norwich and further south through Bramford, a new 400 kV substation at Bramford with all circuits from Norwich Main, Sizewell, Pelham and Rayleigh turned in and a new section of 400 kV double circuit overhead line, approximately 35 km in length from Bramford to the existing tee point down to Rayleigh (near Twinstead). This would then create two double circuit routes to the west out of Bramford for completion by 2017.

200. The cost of onshore works above is estimated to be £400M, for completion in 2017.

Chapter 9 - London

201. Apart from some small CHP projects, there is no generation in the London area except for the large concentration of coal, oil and gas-fired plant in the lower Thames estuary. More distantly, there are nuclear units at Sizewell and Dungeness to the east and south, and the coal and gas plants at Didcot and Marchwood to the west. Consequently, the demand in London is predominantly met by transmission connections from remote generation sources.

202. In essence, the transmission system in London and the South East consists of three circumferential transmission 'rings' surrounding the capital, interconnected by radial circuits.

203. In more detail:

- There is an outer 'ring' of 400 kV overhead lines running about 25 – 50 miles from London. It interconnects the generation in the Thames Estuary, Sizewell, Dungeness, Fawley/Marchwood and Didcot. The northern section of the ring forms the termination of the transmission lines connecting to the Midlands and the North. Further circuits extend to the west.

- A 275 kV ring roughly follows the route of the M25 motorway, and has substations supplying the outer suburbs. This ring is fed by six 400 kV radial routes extending inwards from the 400 kV ring.

- Further 275 kV circuits cross the capital, linking the centre to points on the 275 kV ring. Parts of these routes, such as those between Laleham, Ealing, Willesden, St. John's Wood and Tottenham, consist of 275 kV cables which are approaching the end of their useable lives.

- In central London, a smaller ring of 400 kV cables is being established. This interconnects Hackney, West Ham, City Road and St John's Wood, supplying most of the demand in the City and West End. This ring is supplied by a 400 kV line from the estuary in the east, and from the outer London 400 kV network via a cable from Elstree in the North East. This inner 400 kV ring is also connected to the 275 kV network at Hackney and St. John's Wood. Further 400 kV cables connections will supply this ring in future as the ageing 275 kV cables are replaced.

204. The transmission network in and around London is illustrated in Figure 9.1, below.

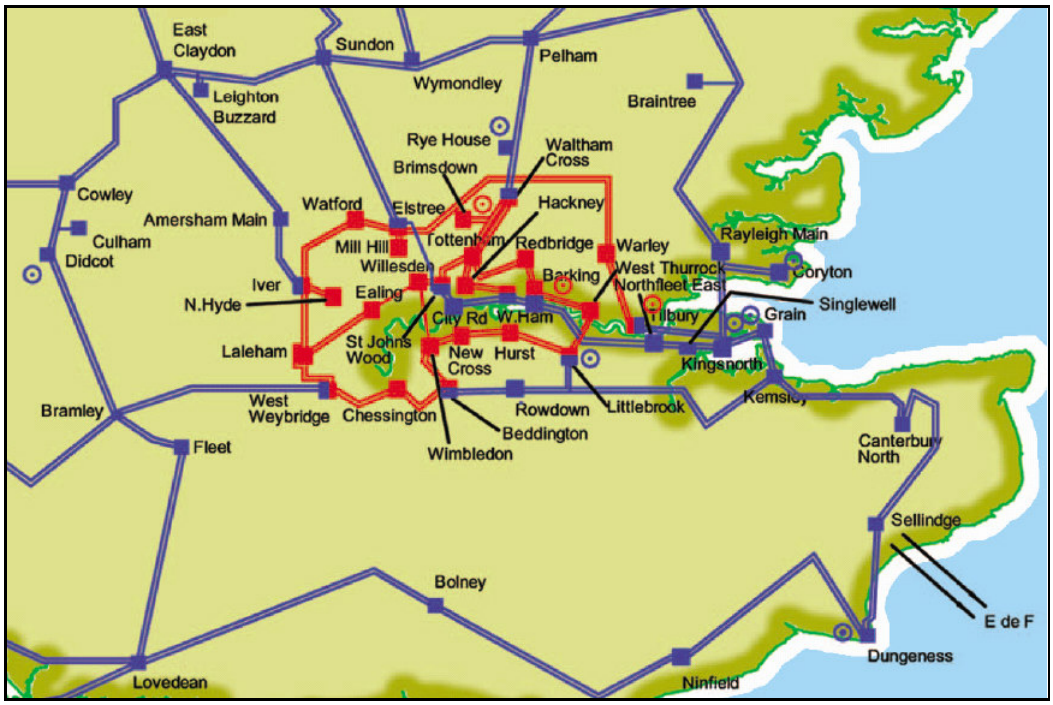


Figure 9.1: Transmission Network in the London area

205. Historically, the network in and around London was developed to secure demand in the capital and its surroundings, when the major generation sources were the oil and coal fired plant in the Thames Estuary, or the coal-fired plant in the East and West Midlands. Additionally, it handled transfers to and from the interconnector with France located at Sellindge.

206. The 275 kV assets, particularly the cables in inner London, are ageing and are gradually being replaced, generally by new 400 kV lines and cables. However, several factors associated with the introduction of new low-carbon generation and liberalisation of European energy markets drive a need for additional transmission capacity in the London area. These are:

- The development of offshore wind power landing on the East Coast, both in Humberside/Lincolnshire and in East Anglia;
- Likely large nuclear developments at Sizewell and Dungeness, and/or Bradwell;
- Development of new clean coal and gas-fired generation in the Thames Estuary;
- New interconnections with the continent from the Estuary and from the south coast.

207. As a consequence there will be a need for additional transmission feeding central London from the north-east, and ultimately a need to reinforce east-west ties.

208. The propose reinforcements are:

- To reconductor the existing 400 kV circuits between Pelham and Waltham Cross to increase their capacity.
- To uprate a 275 kV overhead line from Waltham Cross to Hackney via Brimsdown and Tottenham to 400 kV. This will involve substation works at Waltham Cross and Hackney, and new 400 kV substations at Brimsdown and Tottenham.
- In the longer term, part of the 'middle' 275 kV ring between Tilbury, Warley, Waltham Cross and Elstree would be uprated to 400 kV to provide additional capacity between the Estuary and north London.

209. The Pelham – Waltham Cross – Hackney reinforcement avoids the need for investment on the Pelham – Sundon - Wymondley circuits and on the Sundon – Elstree – St John's Wood route. These would include a second Elstree – St. John's Wood cable, and be costlier than the proposed reinforcement as well as less effective.

139. The locations of these reinforcements are shown in Figure 9.2

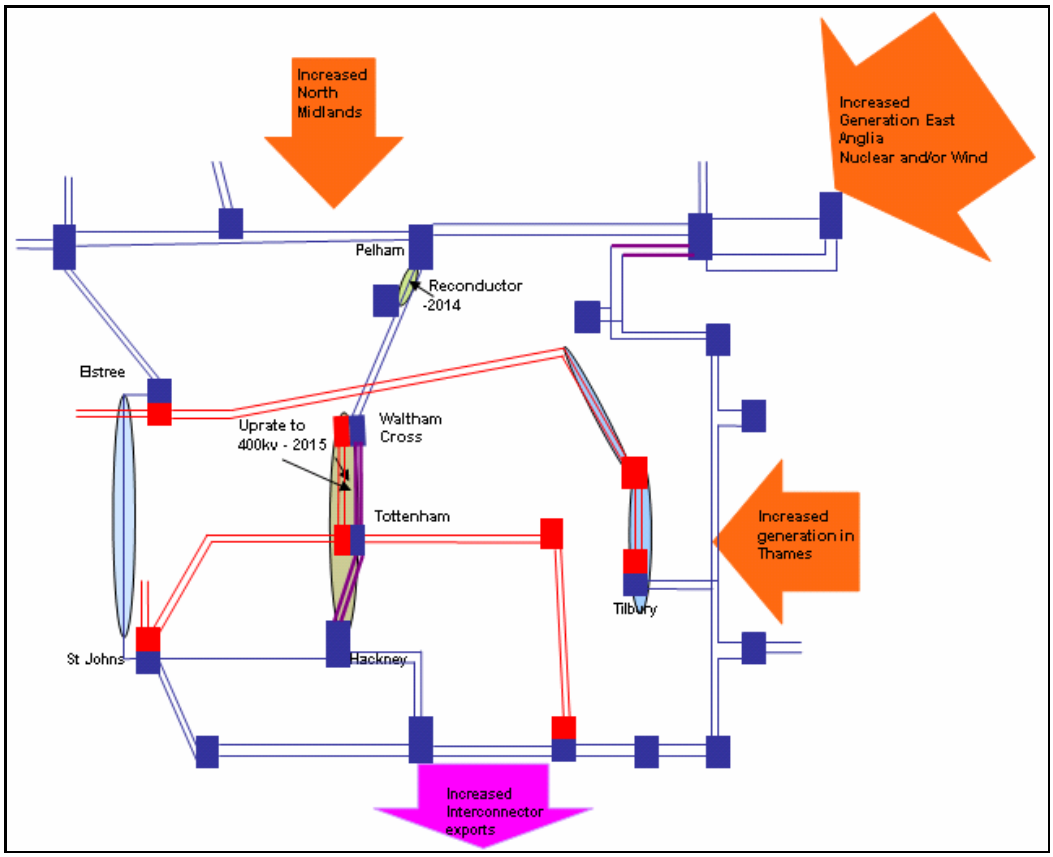


Figure 9.2: Proposed System Reinforcements and Related Drivers

Chapter 10 - Innovative Transmission Technology

Introduction

210. As described earlier, to help combat climate change and to lower carbon emissions, the UK Government has set a number of targets associated with the contribution of electrical energy provided by renewable sources and the level of carbon emissions produced from electrical power generation. The GB transmission system will play a key role in meeting these targets.

211. The GB transmission system is designed to meet the prevailing generation and demand conditions. This philosophy means that there is very little 'spare' capacity available on the network as new generation connections and network reinforcements are handled on a case by case basis. In order to facilitate the meeting of EU and UK government targets the GB transmission system will require significant development.

System Requirements

212. The main approach to meeting the targets described above will be through the increased contribution of renewable electricity generation to the UK's installed capacity. This renewable generation will mainly consist of large-scale onshore and offshore wind farms. In addition to this new generation, the coming decades will also see the closure of many existing conventional thermal generators as they come to the end of their operational life. This changing generation profile, both in terms of equipment type and geographical location, will result in significant changes to the direction and volume of power flows across the network. Historically, it could be assumed that there has been an excess of generation over demand in the north of the country and a deficit of generation relative to demand in the south, leading to power flows on the transmission network from the north towards the south. As the network evolves to meet future needs this north-south flow may increase substantially across the Scotland/England border, and higher power flows from the east coast (offshore wind) to the south.

213. The objective of the proposed system reinforcements or expansions discussed in this report are to allow the connection of new generation developments, to maintain and improve system stability or to enhance the power transmission capabilities across various network boundaries. For example, the large volumes of offshore wind generation that will be sited off the east coast of England will require not only an economic and efficient design for bringing the power ashore but also create a need to enhance the capacity of the onshore system in this area. Another example can also be found in the Scotland to England transmission circuits. At the moment there are two double circuit connections between Scotland and England which are capable of transferring around 3.3 GW

of power. As the amount of renewable generation in Scotland increases, the potential power transfer is expected to rise in excess of 6 GW by 2020 therefore a solution must be found which allows for high power transfers without having any negative effect on system stability.

214. Although traditional solutions, such as building new AC overhead line routes, could be used to meet future network requirements, these projects would likely be subject to major difficulties in obtaining planning consents. It is therefore essential that new technologies and solutions that have not previously been used on the GB transmission system be investigated. In many cases these alternative design options may offer benefits such as smaller land requirements, lower environmental impacts, superior technical performance, enhancing existing assets and in some cases be delivered at a lower cost to traditional approaches.

Innovative Transmission Technologies

215. There are a number of transmission technologies that have either not previously been used in the UK or are new developments which have only recently emerged into the commercial market. The main options that have been considered for the projects discussed in this report are: series compensation, High Voltage Direct Current (HVDC) transmission, energy storage and developments in land and submarine high voltage cables.

Series compensation

216. Using AC overhead lines to transmit power over long distances is impractical due to the large power losses incurred and the reduced system stability caused by the difference in phase angle at the sending and receiving ends of the line (this difference increases with line length). Series compensation can be used to increase the power transfer capacity of long AC transmission lines by reducing the capacitive reactance of a line at power frequency.

217. Capacitors are placed in series with the transmission line reducing the total capacitive reactance and making the electrical distance between two ends of a line appear to be shorter. This improves both angular and voltage stability and allows power transfer at levels well in excess of the natural loading of a line. Series compensation has allowed AC power transmission over distances of more than 1000 km to become possible. In the 1990s, thyristor controlled series compensation (TCSC) was developed in order to further improve the dynamic performance and controllability of series compensation.

218. The main benefit offered by series compensation is the ability to increase the power transfer capability of the network without having to construct new overhead line routes. However, series compensation installations

are still physically very large and finding suitable areas to site them along existing routes will be a key concern. Upgrading an existing line with series compensation also results in significant cost savings when compared with the construction of a new line. Series compensation can also be used to give greater control over the system such as ensuring balanced power flows to reduce losses.

219. Although not previously used in the UK, series compensation is a mature technology and has been used extensively throughout the world since the 1950s. However, there are a number of reasons why its use would still represent a major step change in system design in the UK. Series compensation is predominately used to interconnect separate regions within large countries by compensating very long transmission corridors or to connect remotely located generation such as hydro electric power stations. It has rarely been used as an integral part of a compact and highly meshed network such as the GB transmission system, reasons for this include the extensive system modelling required to ensure consistent performance under different system conditions and the potential for series compensation to introduce sub-synchronous resonance into the network.

220. Series compensation has the potential, under certain conditions, to introduce electrical resonance into the system. These resonances may interact with the mechanical torsional resonances in turbine generator shafts of nearby thermal generating plant. This interaction can affect generator performance, or in the worst case, damage the turbine shaft. Sub-synchronous resonance was identified in the 1970s when a generator shaft was destroyed in California, since then the phenomenon has become well understood and can be prevented through pre-construction system analysis and the use of TCSC. There have been no major incidents caused by sub-synchronous resonance since the 1970s.

HVDC Transmission Technologies

221. High Voltage Direct Current (HVDC) transmission is the process of converting AC (alternating current) power to DC (direct current). This conversion process is carried out at conversion stations located at either end of a DC link.

222. As described earlier, transmitting power over long distances via AC overhead lines results in large power losses and reduced stability. The use of AC cables to transmit power is affected by the capacitive charging effect of the cable which limits the maximum effective cable length (approximately 70 km). HVDC transmission offers far lower losses and can contribute positively to system stability as well as not being subject to the capacitive charging seen in AC cables. HVDC infrastructure is considerably more expensive than equivalent AC equipment (due to the cost of converter stations) however there is a break point where the savings in reduced power losses offset the higher initial capital outlay.

223. There are three main types of HVDC converter station technology; Current Source Converters (CSC), Voltage Source Converters (VSC) and Capacitor Commutated Converters (CCC). Benefits common to all HVDC links regardless of converter type are:

- Reduced losses compared with AC overhead line transmission;
- Ability to contribute positively to system stability through control of power flows, voltage control and system damping;
- HVDC links do not contribute to system short circuit levels, hence adding a link will not place additional stress on existing protection equipment;
- HVDC links prevent fault effects from propagating throughout the network.

224. There are already two CSC based HVDC links in service on the GB transmission system (Scotland – Northern Ireland and Anglo – French links). CSC technology has been in use worldwide since the 1950s and is well understood by UK transmission and distribution companies.

225. Capacitor commutated converters are a modified version of the standard CSC design. CCCs use series capacitors to provide the reactive power required by the converter station to carry out the AC/DC conversion process. The standard CSC design uses parallel or 'shunt connected' reactive equipment to provide this reactive power. Using series capacitors means that smaller capacitors are needed and hence the overall size of the converter station site is reduced. CCCs can also operate at points in the network where the short circuit level is lower than a CSC would require to ensure commutation. CCCs have not been widely used since their introduction in the late 1990s and the benefits they provide over conventional CSCs are not significant.

226. The voltage source converter is a relatively new development which offers a number of advantages over current source converters. The first commercial installation of an HVDC link using VSCs was in Sweden in 1997. VSCs use Insulated Gate Bipolar Transistor (IGBT) semiconductors in the AC/DC conversion process whereas classic CSCs use thyristor valves; the key difference is that the use of IGBTs allows a VSC to be self commutating.

227. To allow the AC/DC conversion process using thyristor valves a current source converter requires both a strong synchronous voltage source and an external supply of reactive power, voltage source converters require neither of these. This difference means that VSCs offer the following advantages over other HVDC converter types:

- The external supply of reactive power to a CSC comes from a combination of the converter station AC filters and additional reactive compensation equipment such as mechanically switched capacitors, this equipment makes up a significant part of a converter station

footprint. As this is not required for a VSC the land requirements are significantly smaller even compared with a CCC.

- The power electronics used in the conversion process allow a VSC to independently control both active and reactive power. This gives far more flexible and fast acting control than that offered by CSCs or CCCs.
- Being self commutating VSCs do not require a strong synchronous voltage source to operate, therefore they can be sited almost anywhere within a network regardless of short circuit ratios.
- The conversion method used in a VSC produces fewer harmonics than CSC or CCC equivalents. This reduces the need for AC filtering equipment and further reduces the overall converter station size.
- Unlike a CSC or CCC, a VSC does not have a minimum power operating limit. VSCs can still provide reactive power to the system and help voltage control even when active power transfer is zero. This gives further support and flexibility for system operation.
- VSCs are well suited to offshore applications. If a CSC or CCC was used offshore the additional equipment required on the platform (reactive equipment, synchronous voltage source etc) would make construction uneconomic and impractical. VSCs do not present these problems and can be designed in a compact modular fashion for offshore use.
- VSCs can also be used to create large-scale multi-terminal HVDC networks (not just point to point connections) far more easily than by using other converter types. These could be used to integrate and optimise offshore wind farms or to allow large sections of the onshore system to be converted to HVDC operation.

228. Worldwide use of VSC HVDC links has increased steadily since its introduction in 1997. There are currently around 20 operational VSC HVDC links in service with several more in the planning or construction phase.

229. The use of VSC HVDC in the GB transmission system has two main risks. The largest VSC HVDC link currently in service is rated at 400 MW; for the projects being considered to enhance the GB transmission system, links rated at around 1 GW would be required. Although manufacturers state that these products are available and could be delivered in the required timescales there have been no projects of this scale delivered previously and we are not aware of any having being ordered. The second risk is the fact that VSC is a new development and hence long term operational and reliability information is not available. However there is no evidence to suggest that the technology will be any less reliable than conventional HVDC transmission technology.

Cable Technology

230. When considering HVDC links, the cable used to transmit the DC power can represent a significant percentage or, in some cases, the largest part

of a project cost. Hence it is vital to understand all implications related to the cables before any HVDC project can be sanctioned.

231. There are two main types of cable technology available; mass impregnated oil insulated cable and extruded polymer insulated cable.

232. Mass impregnated (MI) cables used oil impregnated paper as an insulator, these cables have been in use for several decades and have well proven performance and reliability. MI cables can be used for both land and submarine applications. MI cables can be used with all types of HVDC converters.

233. Extruded polymer insulated DC cables are a new development that is used with voltage source converters only. Extruded cables are unsuitable for use with CSCs and CCCs due to the fact that in order to reverse power flow using these systems the polarity of the DC voltage is reversed, extruded cables become polarised and hence cannot reverse the voltage polarity making power reversal impossible. VSC links can reverse power direction by changing the direction of the current only.

234. Extruded cables offer a number of advantages over MI cables; the different insulation medium allows for a more compact and lighter design which has a significantly smaller bending radius. This allows greater lengths of cable to be loaded onto drums or laying ships meaning longer sections can be laid before jointing is required. Extruded cables also offer environmental benefits; due to the fact that oil is not used as an insulating medium there is no risk of leakage and pollution, and as the cables are more compact they can be easily buried underground with minimum visual impact.

235. The main drawback associated with extruded insulation DC cables is that they are currently only available at ratings which meet the capability of voltage source converters. Hence for a single bipole cable configuration the maximum rating offered by manufacturers is ~ 1 GW +/-320 kV. As with 1 GW voltage source converters there are no examples of extruded DC cables of this rating having been manufactured and installed, however, suppliers state that they can be delivered.

236. A major consideration for offshore projects is the cost of laying a submarine cable. Laying cables onto an uneven rocky sea bed is vastly more expensive than laying in flat sandy conditions. Detailed sea bed surveys will be required to accurately assess any offshore project costs.

Energy Storage

237. It is widely known that it is difficult to store large volumes of electrical energy; as a result, that energy needs to be converted to another form that can be stored, e.g. thermal, potential or chemical, and released

when needed. Until recent times the requirement for large scale (hundreds of MWs) energy storage on the transmission system has been minimal. Forward knowledge of energy demand and power generation capability allows system operators to successfully match supply and demand. This was helped by a strong generation mix in which no one generation type was relied upon too heavily.

238. However, over the next twenty years the increasing penetration of less flexible and controllable renewable generation into the relatively isolated GB transmission system will make balancing supply and demand increasingly difficult. These difficulties will be exacerbated by the closure of existing conventional plant and the potential increasing use of nuclear generation. The low flexibility of nuclear plant and the intermittency of renewables may naturally lead to a market for energy storage devices to maximise the benefits gained from renewable sources and to improve system security.

239. Large scale energy storage is already practised in the UK in the form of hydro-electric power stations such as Dinorwig. This method of energy storage is one of the few to be relatively easily scalable and can operate at transmission system level. There are several other energy storage technologies that have been used throughout the world or are currently in development, many of these cannot practically be applied on the hundreds of MWs scale but may be well suited to providing other services. There are however, some energy storage technologies which may be able to operate on a similar scale to hydro-electric power generation. It is vital that these technologies are investigated and understood at an early stage so that as new generation connections or network changes are carried out, all design options are exploited to ensure that benefits are gained.

Conclusions

240. The ability to enhance the network through maximising the use of existing assets and by building new infrastructure that is less intrusive than conventional design options means that technologies such as series compensation and VSC HVDC are well suited to playing a key role in the major re-development of the GB transmission system.

241. The technologies described above offer many advantages in terms of technical performance, construction requirements, cost and environmental impacts. However there are areas in which extensive further work will be needed to ensure their suitability for use. For example, series compensation would require exhaustive network analysis to be undertaken to guarantee correct operation and no resonance issues. VSC HVDC technology on the scale required would represent a major step forward for manufacturers both in terms of design and delivery. The potential for multi-terminal HVDC also remains an unproven but attractive concept.

242. Despite the advantages over traditional system enhancements all of the technologies described above still involve major construction projects. To deliver these projects in the necessary timescales will be a significant challenge for the transmission licensees.

The Way Forward

243. When considering the use of new technologies or technology that has not previously been used on the GB system it is important to ensure that all issues associated with these systems (technical, commercial and environmental) are fully understood prior to commitment to construct. Discussions have already taken place with manufacturers to assess what technologies could be used in future network developments and what designs represent feasible options considering the required timescales. By developing close working relationships with manufacturers it is possible to identify all potential applications for new technologies and hence ensure that maximum benefit can be gained from their use. However, the licensees will need to be able to accurately model new technologies in order to remain informed asset managers.

244. In many cases using new technologies appears to offer significant benefits over traditional design options. However, when comparing a new or unused technology with existing design options it will be necessary to quantify any benefits or drawbacks accurately to ensure that the optimum design is selected. This process will need to take into account factors including; capital cost of equipment, consents risks, construction costs and timescales, performance benefits for the transmission system, losses, supply chain issues, maintenance requirements, reliability and environmental impact. This can be achieved through working closely with manufacturers and other TOs with experience of the technology.

Chapter 11 - Indicative Cost and Programme Issues

Capital Costs

245. The capital cost estimates have been derived from a range of sources. These are all based on desktop analysis using mid 2008 price levels and do not include inflation or financing.

246. For the HVDC links cost estimates, these have been based on budget information obtained from manufacturers and consideration of information available on the internet relating to sea-bed conditions. Route lengths have been estimated from GIS mapping systems, and will be subject to greater accuracy once constraints have been identified and evaluated and sea-bed surveys have been undertaken.

247. Substation extension costs have been derived in many instances from supplier based estimates or where a range of projects have had cost-estimates produced in response to connection applications, or similar asset replacement schemes for elements of the works considered.

248. Series compensation costs have been based on budget estimates provided from equipment manufacturers plus estimations of the costs of site establishment, civil and interface works etc.

249. Overhead line cost estimates are based on 'generic' rates that assume overall 'average' installation conditions, relating to access difficulty, ground conditions and routeing. These assume lengths of route that are in straight lines without extensive deviation or angle towers, and that no portions of the routes require underground cables.

250. As the majority of the equipment is sourced from outside UK these prices will be subject to variations in exchange rates. Outturn costs are also subject to changes in commodity prices.

251. The following costs have been estimated:

Sector	Cost £M	Comment
SHETL B1 Stage 1 Works	180	Beauly-Dounreay 2nd Conductor Beauly-Kintore Reconductor Knocknagael Substation
SHETL B4 Stage 1 Works	150	East Coast 400 kV Re-insulation and 275 kV Reconductoring Upgrade
SHETL B1 Stage 2 Works	450	Caithness – Moray Upgrade
SPT – East Coast Upgrade	135	Harburn-Grangemouth & Kincardine- Longannet uprate to 400 kV, new 400 kV substations. Smeaton 400 kV substation

SPT- Series Compensation	85	Six Series Compensation installations in circuits to England
SPT East-West 400 kV Upgrades	80	Strathaven- Wishaw – Kaimes – Smeaton 400 kV works, Increase capacity Torness- Eccles
Incremental – National Grid	175	Reconductoring Harker to Quernmore plus 3 Series compensation installations,
Western DC Link	762	Includes SPT estimate for SPT works. Deeside 400 kV replacement. DC converters, 340 km single DC circuit.
North Wales	360	Wylfa Pentir, Second Pentir-Trawsfyydd circuit, series compensation and reconductor Trawsfynfydd- Deeside
Anglia	513	Reconductor Walpole-Norwich-Bramford, Develop Bramford 400 kV substaiton, New line Bramford-Twinstead. Series compensation Norwich-Bramford. Rebuild Walpole. Add QB's into Walpole- Pelham circuits
Humber	523	DC converters, New 400 kV (substation Humber, 130 km single DC circuit.
Eastern DC Link	700	DC converters, 360 km single DC circuit, New 400 kV substation Hawthorn Pit, Norton- Hawthorn Pit single circuit uprate to400 kV. New 400 kV substation Peterhead.
Waltham Cross-Hackney	182	New 400 kV substation, up-rate existing line to 400 kV operation. Replace SGT's
Hinkley- Seabank	340	New 43 km 400 kV overhead line Bridgewater-Seabank. Modify Bridgewater and Seabank substations, new 400 kV Hinkley substation.
Mid Wales	225	Establish new connection into mid Wales from Midlands for Wind farm connections.

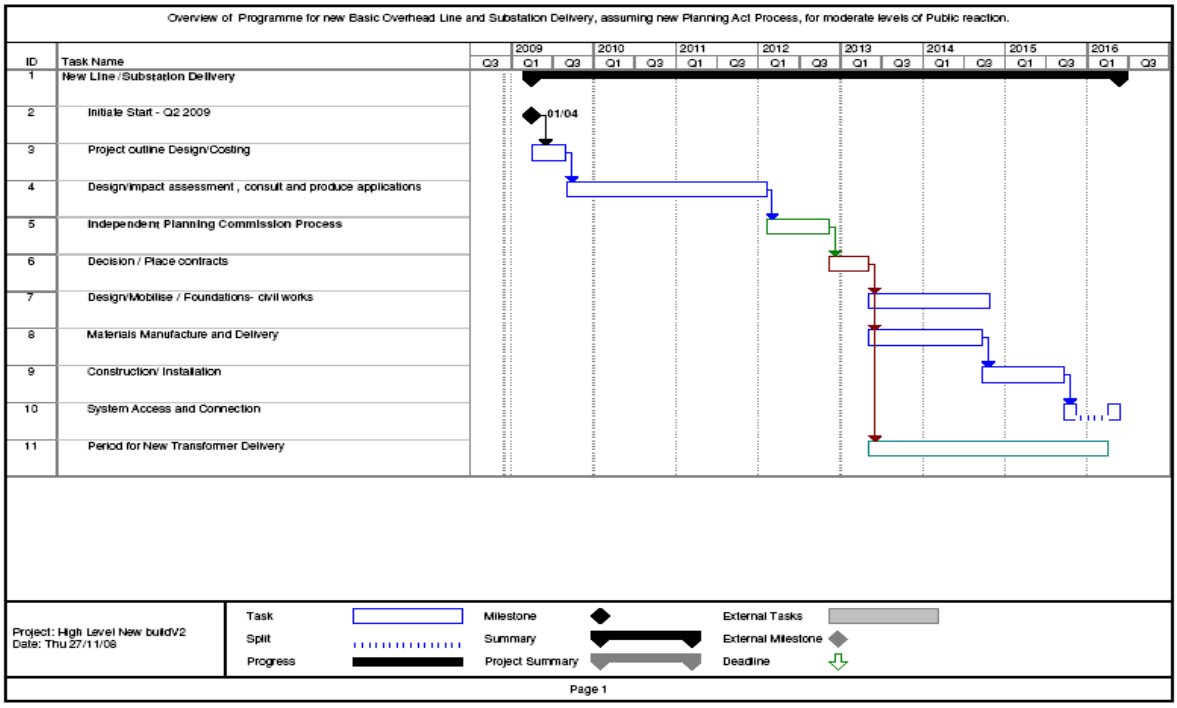
252. The above costs are for the required upgrades to the main interconnected system and exclude the provision of subsea links to the Scottish Islands and offshore network costs for offshore wind.

Construction Timescales

253. Construction timescales have been based on typical overall periods for project design, authorisations, material supply, civil works and installation. The dominant issue for the majority of the works relates to where planning permission or Section 37 consent (in the case of overhead lines) is required. The actual time required to undertake the required assessments and consultations will vary with the extent and 'difficulty' of the locality. The processes scheduled consider the requirements of new Planning Act in England and Wales and have made assumptions over the associated time periods required.

254. A typical estimated programme for the delivery of a moderate length of overhead line, or a new substation, is indicated below. This indicates an anticipated overall time period of approximately seven years for a new circuit to be created.

255. For substation extensions and localised overhead line diversions the assumed time period to obtain the required planning permission and consents is approximately three years.



256. The programme above assumes moderate levels of public reaction to the proposals and also assumes that no significant environmental or local impact issues arise that require major revision to the project design.

257. For the Western DC link, and the Series Compensation installations in particular, the programmes for delivery are more complex as these require a range of co-ordinated activities to be closely managed to achieve the required delivery dates. These fall into the following categories:

A. Joint TO Studies in conjunction with suppliers to achieve suitable network modelling, and define the performance specifications required.
B. Co-ordination of technical specifications, and commercial arrangements between National Grid and Scottish Power to ensure compatible designs, performance and ownership/responsibility allocation.
C. Development of site designs and construction phasing with other, existing 400 kV substation/route projects to ensure adequate site area is available, at the appropriate times, and system configuration and access requirements are minimised.
D. Arising from the above the appropriate assessments and mitigation measures to be identified and their designs incorporated into the overall development to be able to achieve successful planning permission applications.
E. Multiple parties require consultation and agreements entering into for the submarine cable route which is likely to include England Scotland, Isle of Man, and possibly Irish territorial waters. This requires the earliest identification of possible route corridors, and consultation.

258. For the DC link the constraints/risk associated with manufacturing, weather windows and installation vessel availability requires early commitment to secure resources.

259. To achieve a 2015 completion date will require that the above activities be commenced immediately.

260. Several areas of work introduce impacts on third parties, whose co-operation will be required to meet the planned completion dates. One key example is the provision of the second circuit between Pentir and Trawsfynydd. The majority of this route is operating at 132 kV as part of the SP ManWeb network accommodated on the National Grid overhead line towers. For National Grid to obtain access to this circuit will require SP ManWeb to undertake modifications to their network, which may require consent and planning permissions by SP Manweb, and probably regulatory agreement to any costs settlement. Discussions need to commence as soon as agreement to proceed is obtained.

Supply chain issues

261. The most immediate aspects are those relating to the DC links. The market for DC converters and submarine cables is at a peak with many projects worldwide, and wind farm projects utilising the available manufacturing and installation capacity. Only two large capacity submarine cable installation vessels, which would be required for the

Scottish link, are in operation. Their availability is influenced not only by the market demand, but also by the impact of weather systems on installation periods. Securing DC converter and submarine cable manufacturing and installation resource is a key issue. It is proposed that this is achieved as early as possible through appointing a preferred supplier as part of a competitive procurement strategy including participation in the network modelling and performance phase. This will require the payment of a retainer to secure the capacity whilst routing, licensing and planning aspects are resolved, prior to releasing full commercial commitment.

262. In addition to the DC links, overhead line design and installation resources also require early identification and a strategy to address these agreeing with the suppliers. This may require additional teams being introduced from overseas, and/or recruitment and training to supplement existing UK based workforces. Considering that there will also be a demand for these resources arising from the Scottish TOs to undertake their infrastructure extensions, this is another area of risk to be managed.

263. The amount of overhead line and network design effort that will be required to support the consenting processes, including responses to consultation to demonstrate a range of alternative solutions/designs is a major constraint to being able to progress all the new line works. Prioritisation and phasing of the work will require determining to best utilise this area of skills.

Outages Required.

264. System access, ie the ability to secure the outages to undertake the network changes required, is a constraint on the programme to achieve these works. Existing commitments to meet connection dates for generator connections, plus the need to meet other commitments impacting on circuit availability all require to be resolved. With the nature of the uncertainty relating to when consent for new overhead lines or planning permission for substation changes can be expected, plus the risks that consent may not be granted in key areas, firm plans for system access requirements cannot be determined at this time.

265. The circuit reconductoring outages could be estimated and scheduled, however where these can also be associated with other works such as installing series compensation or other major substation changes, the maximum efficiency will be achieved in co-ordinating all the works into single outages. This requires more detailed engineering to be undertaken to fully develop plans to achieve this. Again where planning permission or Section 37 consent is required this adds uncertainty into the programme. As many of the reconductoring routes will require installation works over two to three years outage seasons, contingency plans to address this need developing.

Environmental Concerns

266. The creation of any new major transmission asset, or major change to an existing installation requires that the environmental impacts be fully assessed.

267. The works identified have all been considered in relation to data, such as Ramsar, SPA, SSSI and SAC designated areas available at a high level, such as the MAGIC website[17], and no issues identified that creates major threats to the viability of the proposed works. Part of the initial works to be undertaken for any of the proposed developments would be environmental constraints mapping, to identify any issues to be addressed.

268. To guide the siting and routeing of new high voltage electricity transmission infrastructure, National Grid also has sets of 'Rules' relating to the overhead line and substation developments – the Horlock and Holford Rules. Coupled with best practice approaches in environmental impact assessment, these provide a well accepted set of high-level governing principles underpinning the approach to be taken in seeking to minimise the potential environmental impacts associated with such new installations.

269. Concerns arise in relation to any new 400 kV overhead line route proposals, where the visual impact of the new structures plus the associated disruption caused by tower locations and their construction activities raise many local issues. These will be fully addressed through impact assessments and the associated routeing and consultation exercises. Detailed impact assessments and route selection exercises will also apply to the submarine, and land, DC cable routes and their associated consents/permissions.

270. The construction of new DC converter stations are major installations, expected to occupy around 4.5 Ha of land each. These and their associated substations will be subject to detailed site location studies to determine the most appropriate location, apart from Deeside where land adjacent to the existing substation and power station is available, and considered appropriate.

271. The estuary adjacent to Deeside substation is covered by a range of environmental categories which may prevent the installation of submarine cables in this area. This would be overcome by installing land cables from a suitable landing point on the North Wales coast.

272. The proposed Series Capacitor installations represent the introduction of 'new' technology to the system and their environmental issues, such as noise, visual impact, contamination risk plus disposal issues etc. will all

[17] http://www.magic.gov.uk/website/magic/

require identifying and evaluating as part of the overall assessments to identify the most appropriate design and locations to install these.

Impact of Delay

273. To deliver the scope of works identified in the timescales required to meet the overall targets, requires that study, engineering and consenting activities begin immediately, plus commercial/procurement processes in relation to the DC links. Any delay to commencing these works will have a corresponding delay to the completion dates.

274. The identification and allocation of the key resources necessary to commence with these activities is, in itself, a challenge and outsourcing and bureau staff are likely to be required. The time to achieve this and commence on the detailed activities will require several months of mobilisation.

275. In addition to any system support costs that arise from delays in completing the works to the dates indicated there are also potential additional cost increases that arise out of delays in commencing the overall scope:

A. Reconductoring/uprating lines to 400 kV
If clear direction is not available on the programme to undertake these works this could result in other scheduled works – e.g. fittings replacement - proceeding. This will result in additional system outages plus the grantors and public will raise concerns over duplication of tower access, scaffolding etc.

B. Substation Asset Replacement/extensions
There are existing projects to undertake asset replacement and extensions to substations. If the design activities are undertaken without the scope of the Strategic Works being incorporated into these then the designs and construction undertaken may not permit later works to be undertaken in the most economic manner. This will result in additional costs, system access, scope and may undermine aspects of planning permission submissions. In extremes this could require additional land purchases.

C. Siting Studies: Series Compensation
The introduction of new Series Capacitor installations into several existing 400 kV routes requires that appropriate locations for these are identified and the required planning permission and overhead line entry Section 37 consent obtained. Most of these installations are on routes that are also scheduled for reconductoring. To achieve the most efficient utilisation of system access would ideally have the line diversions/entry works undertaken during the reconductoring outages. Delay to commencing the site location identification could result in the need to introduce further system

access outages into the overall programme and write-off of some of the nearly new conductors.

General Design/Consenting Activities

276. Where substation and overhead works are planned there is a need to co-ordinate the designs and address the outcome of environmental assessments in an integrated manner. This affects the ability to produce a comprehensive planning/consents application and construction programme that can be demonstrated to address all issues. System access requirements will be optimised and contingency planning can be undertaken. If too strict limitations are imposed on the scope of works released this could result in inefficient design activity.

Chapter 12 - Cost Benefit Analysis

Cost-Benefit Formulation

277. The reinforcement is justified if

$$\mathbf{T + OUT < O + L} \quad \textit{where}$$

T	=	capital cost of the Transmission Reinforcement;
OUT	=	cost of the Outages needed to accommodate the reinforcement construction;
O	=	Constraints costs saved (discounted over a 15-year horizon)
L	=	Transmission Losses costs saved.

278. In this report we identify cost savings (components O and L in the above equation) with a negative sign, and costs (components T and OUT) with a positive sign. This means that our analysis indicates a benefit if the summation of T, OUT, O and L is itself negative. Conversely, should this sum be positive, our analysis indicates a dis-benefit.

Transmission Network Configurations (T)

279. In this report, eight possible network configurations are assessed. These are described below, together with the associated capital cost of each reinforcement.

280. The timing given for each reinforcement is arbitrary, and is for the purposes of this cost-benefit exercise only. The timings do not reflect the current plants or ambitions of the TOs.
    - The two HVDC links each commission at start 2015, which reflects an optimistic view of what could be achieved. We assess both links commissioning in the same year, to give a consistent comparison.

    - We commission the 'Incremental Reinforcements' one year earlier, which is currently feasible. Thus the 'Incremental Reinforcements' gain one year of Constraints and Losses benefits over the HVDC links in the overall appraisal – we think this represents a fair reflection of the possibility of more rapid development of this option.

Figure 12.1: Description of 2020 Reinforcements

Network	Cost	REINFORCEMENT description
0 'Current Authorised'	*n/a*	*This network already assumes the completion, notionally by 2014, of a number of significant reinforcements from the 2008 networks. Since this is the base case, the costs of all these works are not relevant. Reinforcements include (in the areas of interest):* • *Beauly-Denny single 400 kV circuit;* • *'TIRG' uprates of the Strathaven-Harker and Eccles-Stella routes to a Scotland-England ('Cheviot') capability of 3.3 GW;* • *reconductoring the Heysham 400 kV ring;* • *new circuitry to uprate the Stella-Norton route to 400 kV*
a. 'Incremental Reinforcements'	*£555M* *Incurred 2010 – 2013*	*This maximises the capability of the current system without new circuitry. This includes further upratings of SHETL circuits, and installation of some six series compensators to increase the Cheviot capability. The capital cost of these works is initially set at £555M. This comprises £150M of SHETL works; £300M of SPT (including £85M for six SP Series Compensators); and £105M of NGET works (comprising £75M for six NG Series Compensators, £100M for Hark-Hutt-Quer reconductoring, minus £70M of asset replacement for same).* *Commissions March 2014.*
b. 'Huer-Dees DC'	*£697M* *Incurred 2011 – 2014*	*An offshore 300 kV DC cable of ~340 km from Hunterston to Deeside. For this paper, the capacity is set to 1.8 GW (such a cable is at the limits of current technology), and the capital cost is initially set at £697M, which includes £340M + £200M for the link plus ends, £125M of SPT works, £80M at Deeside, and £17M consents and engineering, offset by £65M of asset replacement. (Note, we may actually seek a cable of more or less capacity; 1.8 GW is merely an estimate, thought to be suitable for this cost-benefit.)* *Commissions March 2015*
a. + b.	*£1,252M* *Incurred 2010 – 2014*	*Both the Incremental Reinforcements (a.) plus the Hunterston-Deeside DC cable (b.) The capital cost of these works is therefore initially set at £555M plus £697M.* *Commissions March 2014 (a.) and March 2015 (b.)*
c. 'Pehe-Hawp DC':	*£690M* *Incurred 2011 – 2014*	*An offshore 300 kV DC cable of ~360 km from Peterhead to Hawthorn Pit. For this paper, the capacity is set to 1.8 GW (again, such a cable is at the limits of current technology). The capital cost is initially set at £360M plus £200M for the link plus ends, and £17M consents and engineering. This reinforcement includes £63M to uprate Hawthorn Pit-Norton to 400 kV and £50M Peterhead substation termination.* *Commissions March 2015.*
a. + c.	*£1,245M* *Incurred 2010 – 2014*	*Both the Incremental Reinforcements (a.) plus the Peterhead to Hawthorn Pit DC cable (c.) The capital cost of these works is therefore initially set at £555M plus £690M.* *Commissions March 2014 (a.) and March 2015 (c.)*
b. + c.	*£1,387M* *Incurred 2011 – 2014*	*Both DC cables: Hunterston to Deeside (b.) plus Peterhead to Hawthorn Pit (c.) The capital cost of these works is therefore initially set at £697M plus £690M.* *Commissions March 2015.*
a. + b. + c.	*£1,942M* *Incurred 2010 – 2014*	*Both the Incremental Reinforcements (a.) plus the Hunterston-Deeside DC cable (b.) plus the Peterhead-Hawthorn Pit DC cable (c.). The capital cost of these works is therefore initially set at £555M plus £697M plus £690M.* *Commissions March 2014 (a.) and March 2015 (b. and c.)*

Outages (OUT)

281. For each network reinforcement, the number of outage-weeks required on major boundaries during construction is costed at a simple £1M or £2M per week, in line with recent experience.

Constraints (O)

282. This is derived from our simple boundary Constraints model. We assess two years – 2015 and 2020 – together with each of the three '3TO' scenarios:

- **GG5c**: the '*Gone Green 5'* scenario of 30 July 2008, as agreed between the TOs; this scenario has 11.4 GW of Scottish Wind capacity.
- **GG5b**: as GG5c, but with 8.0 GW of Scottish Wind and +3.4 GW of English Wind.
- **GG5a**: as GG5c, but with 6.6 GW of Scottish Wind and +4.8 GW of English Wind.

283. The treatment of each of the eight networks in the Constraints model is relatively simple, in that the network is represented merely as the boundary capability for the boundaries modelled[18]:

- B4: SHETL to SPT boundary; constraints and reinforcements on this boundary mainly cover constraints on boundary B2 also; however, deeper boundaries within Scotland, such as B1 and B5, are not represented, and are thus not assessed in this paper.
- B6: SPT to NGET boundary, known as Cheviot.
- B7a: NGET modified Upper North: this is the Upper North B7 boundary, redrawn South of Penwortham rather than South of Harker, in order to capture the export from Heysham and North-West Wind.
- B8: The North to Midlands boundary.
- B9: The Midlands to South boundary.
- B15: The Thames Estuary boundary.

Losses (L)

284. For each of the networks, the I^2R losses are taken from the load flow at ACS peak demand, Planned Transfer condition. These are converted to annual TWh losses via the formula below. This formula calibrates to current year studies, and is considered adequate. Finally, Losses are priced at a simple £60/MWh, which we believe represents a conservative value of future energy 2015-2029.

$$\text{Annual Losses (TWh)} = [\,5000 \text{ hours} \times \text{Peak Losses (TW)}\,] + 2.3 \text{ TWh}$$

Cost-Benefit Data

285. Some of the important data assumptions, which feed into the cost-benefit, are discussed below.

[18] Boundary numbers are as per National Grid's Seven Year Statement ('SYS')

T – Cost of Transmission Reinforcements

286. The eight network reinforcements, and their capital costs, have been described in Figure 12.1. Reinforcements are assumed to commission in March 2014 (a.) or March 2015 (b. and c.), and the capital spend is phased evenly19 across the preceding four years.

287. The achieved boundary capabilities for each network are shown in Figure12.2. The boundary capabilities are the same across the three generation scenarios20. The capabilities listed are for Winter/Summer_intact/Summer_outage.

Figure 12.2: Boundary Capabilities (MW) for 2015 for B4, B6, B7a

	B4 SHETL_SPTL	B6 SYS_CHEVIOT	B7a UPPER-NORTH mod
0_Curr_Auth	3050 / 2400 / 1800	3300 / 2900 / 2100	5000 / 4500 / 3200
a_Incr_Rein	3750 / 3300 / 2600	4400 / 3900 / 2400	5000 / 4500 / 3200
b_Huer-Dees DC	3050 / 2400 / 1800	4900 / 4400 / 3600	7000 / 6500 / 5200
a+b_Incr & Huer_DC	3750 / 3300 / 2600	6000 / 5400 / 3900	7000 / 6500 / 5200
c_Pehe-Hawp DC	4600 / 4000 / 3400	4900 / 4400 / 3600	5600 / 5100 / 3800
a+c_Incr & Pehe_DC	5300 / 4900 / 4200	6000 / 5400 / 3900	5600 / 5100 / 3800
b+c_both_DCs	4600 / 4000 / 3400	6500 / 5900 / 5100	7600 / 7100 / 5800
a+b+c_Incr & both DCs	5300 / 4900 / 4200	7600 / 6900 / 5400	7600 / 7100 / 5800

Figure 12.3: Boundary Capabilities (MW) for 2020 for B4, B6, B7a

	B4 SHETL_SPTL	B6 SYS_CHEVIOT	B7a UPPER-NORTH mod
0_Curr_Auth	3050 / 2400 / 1800	3000 / 2600 / 2100	5200 / 4700 / 3400
a_Incr_Rein	3750 / 3300 / 2600	4350 / 3900 / 2400	5200 / 4700 / 3400
b_Huer-Dees DC	3050 / 2400 / 1800	4600 / 4100 / 3600	7200 / 6700 / 5400
a+b_Incr & Huer_DC	3750 / 3300 / 2600	5900 / 5300 / 3900	7200 / 6700 / 5400
c_Pehe-Hawp DC	4600 / 4000 / 3400	4600 / 4100 / 3600	5800 / 5200 / 4000
a+c_Incr & Pehe_DC	5300 / 4900 / 4200	5900 / 5300 / 3900	5800 / 5200 / 4000
b+c_both_DCs	4600 / 4000 / 3400	6200 / 5600 / 5100	7800 / 7200 / 6000
a+b+c_Incr & both DCs	5300 / 4900 / 4200	7500 / 6800 / 5400	7800 / 7200 / 6000

288. These boundary capabilities have the following features between 2015 and 2020:
   - B4 capabilities are the same in both years;
   - Without incremental reinforcements, B6 winter capabilities are 300 MW lower in 2020 than in 2015, because of assumed tightening of the stability limit, following closure of Hunterston and Cockenzie;

[19] That is to say, incurred ¼ : ¼ : ¼ : ¼

[20] For a given network, boundary capability has a second-order dependence on generation disposition. This effect has been ignored for our generation background scenarios GG5b and GG5a.

- B7a sees a capability 200 MW higher in 2020 than in 2015, for the same network configuration. These are results from load flow studies, and reflect the improved disposition of generation.

289. In addition to these three boundaries, for completeness we study three further within-England boundaries (Figure12.4). These capabilities do not change by network reinforcement, and represent a conservative estimate of the boundary capability of the *'Current Authorised'* system.

Figure 12.4: Boundary Capabilities (MW) for both 2015 and 2020 for B8, B9, B15

	B8 NORTH-MIDS	**B9 MID-SOUTH**	**B15 THAMES ESTUARY**
All network reinforcements	10000 / 9000 / 8000	10000 / 9000 / 8000	6000 / 5500 / 5000

OUT – Cost of Outages

290. Figure12.5 shows the number of outage-weeks required on major boundaries during construction of each network reinforcement, as well as the cost of these outages. Outages are costed at £1M/week on B4 and B7, and at £2M/week on B6. In the cost-benefit phasing, these costs are all deemed to be incurred in the year (or two years) before commissioning (in 2013 or 2014).

Figure 12.5: Outages by Reinforcement

Network	Cost	Outage description
0 'Current Authorised'	*n/a*	*Zero outage-weeks, since this is the base case*
a. 'Incremental Reinforcements'	*£48M + £36M + £33M = £117M*	*At present, we assume that to achieve the 4.4GW Cheviot capability requires only 6 weeks for each of the four cross-border circuits to connect in series compensators. Thus 24 weeks of Cheviot outage (@ £2M/week) are assumed.* *42 weeks of outage across B7 to reconductor Harker-Hutton also required, and a further 18 weeks to reconductor Hutton-Quernmore (assuming 3 gangs co-working, at 1.3 km of single circuit per gang per week). 24 of these 60 weeks are assumed nested with the Cheviot outages above. The remaining 36 weeks are costed at £1M per week, in line with operational experience that B7 outages are less expensive than Cheviot outages.* *33 weeks of B4 outages will be required to replace the conductor on the Kintore – Tealing 275 kV route, costed at £1M per week. (30 weeks of B4 outages for re-insulation of the Blhi-Kint-Teal-Kinc route to 400 kV operation are assumed to be fully nested with asset replacement outages on the Kincardine-Grangemouth-Curry overhead line route, and so represent zero incremental cost.)*
b. 'Huer-Dees DC'	*£0M*	*There will be outages at Hunterston and Deeside substations to connect in the new DC converters. These are not major boundary outages, and can be assumed not to incur a significant cost.*
a. + b.	*£117M*	*As for 'Incremental Reinforcements' plus 'Huer-Dees DC'.*
c. 'Pehe-Hawp DC'	*£4M*	*As for 'Huer-Dees', there will be outages at Peterhead and Hawthorn Pit substations to connect new DC converters, of insignificant cost. Estimate 8 weeks of relatively low cost outages on the Hawp-Norton route to uprate to 400 kV.*
a. + c.	*£121M*	*As for 'Incremental Reinforcements' plus Pehe-Hawp DC.*
b. + c.	*£4M*	*As for 'Huer-Dees DC' plus 'Pehe-Hawp DC'.*
a. + b. + c.	*£121M*	*As for 'Incremental Reinforcements' plus 'Huer-Dees DC' plus 'Pehe-Hawp DC'.*

O – Cost of Constraints

291. Our boundary Constraints model is described in the January 2008 *GRS001 Consultation*, Appendix 5.

292. There are characteristics of the model that are worth highlighting here, since they potentially have a modest effect on the results:

- the model can only constrain on plant located within a very large southern zone in E&W, bounded by B9 to the north and B15 to the east (i.e. SYS zones 12, 13, 14, 16 and 17);
- the model constrains off plant sequentially from north to south.

293. The most important data item, apart from the generation backgrounds of the three *Gone Green* scenarios (GG5c, GG5b and GG5a) and the boundary capabilities listed above, is the generation prices, which have not been changed significantly from the January Consultation:

Figure 12.6: Bid and Offer Prices

Fuel Type	Bid Price (£/MWh)	Offer Price (£/MWh)
Nuclear	-100	n/a
Wind	-50	n/a
Base_Gas	10	40
Base_Coal	15	60
France	20	80
Water	23	90
Marg_Gas	25	100
Marg_Coal	30	120
PumpStor	75	300
Britned	90	360
Oil	100	400
Aux GT / Main GT	150	500

294. These prices represent the average prices we have experienced over 2005–2007 across the broad operation of the Balancing Mechanism ('BM'), by class of plant. The prices are stylised, and do probably represent a slight premium, of no more than 20%, over bulk non-locational actions in the BM. We think this premium appropriately reflects a plausible level of locational premium in a heavily constrained system (which is the state in our un-reinforced studies); it does not reflect any extreme of possible constraint pricing, for example as witnessed over certain periods in 2008.

295. Our model emulates the operation of the Balancing Mechanism, in that constrained-on and constrained-off plant are those plant submitting, respectively, the lowest Offer and highest Bid prices.

296. A fairly typical Constraint action in these studies is to constrain off the 'Base_Gas' plant in Scotland (this means Peterhead), at a Bid price of 10 £/MWh; and to replace with 'Marg_Gas' plant in England, at an Offer price of 100 £/MWh. Thus for most of the studies reported below, the average Constraint price is 90 £/MWh, which follows directly from these Bid and Offer pricing assumptions.

297. Bid prices are highly negative for Wind and Nuclear plant since they are hardly likely to offer National Grid this operational flexibility cheaply, due to commercial and operational considerations. We do not believe that these plant would ever be constrained-on, and hence their Offer prices are shown as 'n/a'.

L – Cost of Losses

298. The peak and annual Losses against each network, under the three *Gone Green* scenarios, are shown in Figure 12.7. These values are derived mainly from load flow studies and partly by interpolation.

Figure 12.7: Losses for GG5 scenarios – Peak (MW)/Annual (TWh)

	Year	0_Curr_Auth	a_Incr_Rein	b_Huer-Dees DC	a+b_Incr & Huer_DC	c_Pehe-Hawp DC	a+c_Incr & Pehe_DC	b+c_both_DCs	a+b+c_Incr & both DCs
GG5c	2015	1304 / 8.8	1264 / 8.6	1216 / 8.4	1176 / 8.2	1204 / 8.3	1174 / 8.2	1164 / 8.1	1133 / 8
	2020	1647 / 10.5	1587 / 10.2	1547 / 10	1487 / 9.7	1492 / 9.8	1442 / 9.5	1442 / 9.5	1411 / 9.4
GG5b	2015	1244 / 8.5	1214 / 8.4	1166 / 8.1	1136 / 8	1154 / 8.1	1134 / 8	1124 / 7.9	1103 / 7.8
	2020	1457 / 9.6	1427 / 9.4	1407 / 9.3	1377 / 9.2	1382 / 9.2	1332 / 9	1332 / 9	1301 / 8.8
GG5a	2015	1214 / 8.4	1184 / 8.2	1136 / 8	1106 / 7.8	1124 / 7.9	1104 / 7.8	1094 / 7.8	1073 / 7.7
	2020	1377 / 9.2	1362 / 9.1	1347 / 9	1332 / 9	1352 / 9.1	1302 / 8.8	1302 / 8.8	1271 / 8.7

Scenario backgrounds

299. The three GG5 scenario backgrounds are shown in Figure 12.8 and Figure 12.9. We identify generation capacity by fuel type in SHET-L, SPT and England & Wales areas, and list the fuel types in accordance with our Offer price merit order.

300. Since the scenarios differ only in the zonal allocation of Wind capacity, it is convenient to show all three scenarios in one table.

301. Our GG5c background assumes that total Scottish Wind capacity in 2015 is 6.9 GW, rising to 11.4 GW by 2020. In 2020, GG5b and GG5a have 8.0 GW and 6.6 GW respectively[21].

302. Wind build rate profiles have been agreed such that the 6.9 GW in 2015 GG5c is allocated between SHET-L (3.7 GW) and SPT (3.2 GW).

303. The reduction in Scottish (onshore) wind by 2020 is reallocated one-for-one to E&W offshore and onshore:
   - compared with GG5c, GG5b sees a total reallocation of 3.4 GW (2.0 GW SHETL and 1.4 GW SPT) of Scottish wind to E&W (2.0 GW at Dogger Bank; 1.4 GW in Central Wales);
   - compared with GG5b, GG5a sees a further reallocation of 1.4 GW (0.83 GW SHETL and 0.57 GW SPT) of Scottish wind to E&W (1.4 GW at Dogger Bank).

[21] These values are often quoted in reference to these scenarios, and hence these values have been highlighted in the 2020 table.

Figure 12.8: Scenario Backgrounds 2015 (MW)

		SHETL	SPT	SCOT	E&W	TOTAL
Nuclear		**0**	**2,289**	**2,289**	**7,155**	**9,444**
Wind	Offshore	0	0	**0**	**4,097**	**4,097**
	Onshore	3,735	3,166	**6,901**	**299**	**7,200**
GG5c	**Total**	**3,735**	**3,166**	**6,901**	**4,396**	**11,297**
	Offshore	0	0	**0**	**4,332**	**4,332**
	Onshore	3,500	3,100	**6,600**	**365**	**6,965**
GG5b	**Total**	**3,500**	**3,100**	**6,600**	**4,697**	**11,297**
	Offshore	0	0	**0**	**5,406**	**5,406**
	Onshore	3,000	2,526	**5,526**	**365**	**5,891**
GG5a	**Total**	**3,000**	**2,526**	**5,526**	**5,771**	**11,297**
Base_Gas	CCGT	0	0	**0**	**12,315**	**12,315**
	CHP	0	0	**0**	**1,218**	**1,218**
	Gas - Other	1,100	0	**1,100**	**0**	**1,100**
	Total	**1,100**	**0**	**1,100**	**13,533**	**14,633**
Base_Coal	Clean Coal	0	0	**0**	**3,200**	**3,200**
	Coal - LCPD In	0	1,152	**1,152**	**11,023**	**12,175**
	Total	**0**	**1,152**	**1,152**	**14,223**	**15,375**
France	Interconnector	0	0	**0**	**1,988**	**1,988**
Hydro	Hydro	**1,095**	**33**	**1,128**	**0**	**1,128**
Marg_Gas	Biofuel	0	0	**0**	**136**	**136**
	Biomass	0	90	**90**	**550**	**640**
	CCGT	0	0	**0**	**17,247**	**17,247**
	CHP	12	243	**255**	**751**	**1,006**
	Gas - Other	434	0	**434**	**0**	**434**
	Total	**446**	**333**	**779**	**18,684**	**19,463**
Marg_Coal	Coal - LCPD In	**0**	**1,152**	**1,152**	**6,581**	**7,733**
PumpStor	Pumped Storage	**300**	**440**	**740**	**2,004**	**2,744**
Britned	Interconnector	**0**	**0**	**0**	**500**	**500**
Aux GT / Main GT	AGT	0	0	**0**	**373**	**373**
	MGT	0	0	**0**	**429**	**429**
	Total	**0**	**0**	**0**	**802**	**802**
Grand Total - GG5c		**6,676**	**8,565**	**15,241**	**69,866**	**85,107**
Grand Total - GG5b		**6,441**	**8,499**	**14,940**	**70,167**	**85,107**
Grand Total - GG5a		**5,941**	**7,925**	**13,866**	**71,241**	**85,107**

304. The following headline observations can be made for all three scenarios:

- There is no oil plant, as this is forecast to close before 2015;
- By 2020 Britned is assumed to be at float;
- Wave & tidal projects begin to come on-stream by 2020;
- Nuclear capacity in 2015 (9.4 GW) is rather higher than in 2020 (6.9 GW);
- Wind farms in Scotland are nearly all sited onshore, whereas in E&W they are nearly all offshore[22].
- There is no additional Clean Coal development between 2015 (3.2 GW, at Kingsnorth and Tilbury) and 2020.

[22] Note that this comment refers to transmission-connected Wind only. In fact, the scenarios also assume 4-6 GW of distribution-connected Wind in E&W, but this is represented as negative demand.

Figure 12.9: Scenario Backgrounds 2020 (MW)

		SHETL	SPT	SCOT	E&W	TOTAL
Nuclear		**0**	**1,200**	**1,200**	**5,703**	**6,903**
Wind	Offshore	200	500	**700**	**17,748**	**18,448**
	Onshore	6,700	4,000	**10,700**	**299**	**10,999**
GG5c	**Total**	**6,900**	**4,500**	**11,400**	**18,047**	**29,447**
	Offshore	200	500	**700**	**19,748**	**20,448**
	Onshore	4,700	2,600	**7,300**	**1,699**	**8,999**
GG5b	**Total**	**4,900**	**3,100**	**8,000**	**21,447**	**29,447**
	Offshore	200	500	**700**	**21,148**	**21,848**
	Onshore	3,874	2,026	**5,900**	**1,699**	**7,599**
GG5a	**Total**	**4,074**	**2,526**	**6,600**	**22,847**	**29,447**
Base_Gas	CCGT	0	0	**0**	**12,077**	**12,077**
	CHP	0	0	**0**	**1,218**	**1,218**
	Gas - Other	1,100	0	**1,100**	**0**	**1,100**
	Total	**1,100**	**0**	**1,100**	**13,295**	**14,395**
Base_Coal	Clean Coal	0	0	**0**	**3,200**	**3,200**
	Coal - LCPD In	0	1,152	**1,152**	**9,076**	**10,228**
	Total	**0**	**1,152**	**1,152**	**12,276**	**13,428**
France	Interconnector	0	0	**0**	**1,988**	**1,988**
Hydro	Hydro	**1,095**	**33**	**1,128**	**0**	**1,128**
Wave / Tidal	Tidal & Wave	**510**	**100**	**610**	**800**	**1,410**
Marg_Gas	Biofuel	0	0	**0**	**136**	**136**
	Biomass	0	90	**90**	**550**	**640**
	CCGT	0	0	**0**	**18,315**	**18,315**
	CHP	12	243	**255**	**751**	**1,006**
	Gas - Other	434	0	**434**	**0**	**434**
	Total	**446**	**333**	**779**	**19,752**	**20,531**
Marg_Coal	Coal - LCPD In	**0**	**1,152**	**1,152**	**5,245**	**6,397**
PumpStor	Pumped Storage	**300**	**440**	**740**	**2,004**	**2,744**
Aux GT / Main GT	AGT	0	0	**0**	**339**	**339**
	MGT	0	0	**0**	**429**	**429**
	Total	**0**	**0**	**0**	**768**	**768**
Grand Total - GG5c		**10,351**	**8,910**	**19,261**	**79,877**	**99,138**
Grand Total - GG5b		**8,351**	**7,510**	**15,861**	**83,277**	**99,138**
Grand Total - GG5a		**7,525**	**6,936**	**14,461**	**84,677**	**99,138**

Constraint Results

305. The above cases result in 48 runs of the Constraints model (ie. 2 years × 3 scenarios × 8 networks). For each study, Figure 12.10 shows the headline GB costs of Constraints; an indicative breakdown of the GB cost of constraints against three specific boundaries, and the average constraint prices for each study.

Figure 12.10: Constraint Cost and Average Constraint Price Summary

£m	2015/16				2020/21			
	Winter Capability	5c (11.4GW)	5b (8.0GW)	5a (6.6GW)	*Winter Capability*	5c (11.4GW)	5b (8.0GW)	5a (6.6GW)
0_Curr_Auth								
B4	*3.050 GW*	36.1	25.1	10.0	*3.050 GW*	466.1	129.6	59.6
B6	*3.300 GW*	213.9	182.1	83.0	*3.000 GW*	343.2	82.8	29.5
B7a	*5.000 GW*	17.4	16.0	12.1	*5.200 GW*	0.3	0.2	0.1
Other Eng & Wales	*n/a*	131.7	128.0	121.1	*n/a*	203.8	170.4	167.3
GB		**399.2**	**351.2**	**226.3**		**1,013.3**	**383.1**	**256.6**
Constraint price (£/MWh)		*94*	*92*	*88*		*95*	*82*	*80*
a_Incr_Rein								
B4	*3.750 GW*	2.2	1.1	0.1	*3.750 GW*	188.2	27.2	7.4
B6	*4.400 GW*	101.2	82.1	34.9	*4.350 GW*	190.1	35.5	12.1
B7a	*5.000 GW*	70.0	59.1	31.1	*5.200 GW*	7.9	3.3	1.3
Other Eng & Wales	*n/a*	137.6	133.3	125.5	*n/a*	190.9	169.3	167.8
GB		**310.9**	**275.5**	**191.5**		**577.1**	**235.4**	**188.6**
Constraint price (£/MWh)		*98*	*96*	*91*		*89*	*81*	*80*
b_Huer-Dees DC								
B4	*3.050 GW*	31.3	22.1	9.3	*3.050 GW*	430.6	125.1	58.9
B6	*4.900 GW*	9.7	7.2	1.1	*4.600 GW*	22.5	0.5	0.0
B7a	*7.000 GW*	0.3	0.3	0.2	*7.200 GW*	0.0	0.0	0.0
Other Eng & Wales	*n/a*	114.2	112.8	112.4	*n/a*	188.3	164.4	165.2
GB		**155.5**	**142.4**	**123.0**		**641.4**	**290.0**	**224.1**
Constraint price (£/MWh)		*81*	*81*	*81*		*88*	*79*	*79*
a+b_Incr & Huer_DC								
B4	*3.750 GW*	1.9	0.9	0.1	*3.750 GW*	172.2	26.5	7.3
B6	*6.000 GW*	4.8	3.5	0.7	*5.900 GW*	10.2	0.3	0.0
B7a	*7.000 GW*	1.4	1.0	0.4	*7.200 GW*	0.3	0.1	0.0
Other Eng & Wales	*n/a*	116.5	114.9	113.4	*n/a*	174.7	165.0	166.8
GB		**124.6**	**120.3**	**114.5**		**357.5**	**191.9**	**174.1**
Constraint price (£/MWh)		*83*	*83*	*82*		*81*	*79*	*79*
c_Pehe-Hawp DC								
B4	*4.600 GW*	0.0	0.0	0.0	*4.600 GW*	60.0	2.4	0.2
B6	*4.900 GW*	21.2	14.1	2.2	*4.600 GW*	168.6	14.0	1.3
B7a	*5.600 GW*	45.3	37.6	15.2	*5.800 GW*	9.7	3.2	1.3
Other Eng & Wales	*n/a*	131.8	128.0	120.6	*n/a*	190.0	167.3	166.8
GB		**198.3**	**179.7**	**138.0**		**428.4**	**186.9**	**169.6**
Constraint price (£/MWh)		*94*	*92*	*87*		*88*	*80*	*80*
a+c_Incr & Pehe_DC								
B4	*5.300 GW*	0.0	0.0	0.0	*5.300 GW*	13.2	0.0	0.0
B6	*6.000 GW*	6.8	4.5	0.7	*5.900 GW*	71.1	2.6	0.2
B7a	*5.600 GW*	58.1	45.5	16.3	*5.800 GW*	48.5	7.0	1.5
Other Eng & Wales	*n/a*	135.8	130.7	121.3	*n/a*	180.7	166.0	166.8
GB		**200.6**	**180.7**	**138.3**		**313.5**	**175.6**	**168.5**
Constraint price (£/MWh)		*96*	*94*	*88*		*84*	*79*	*80*
b+c_both_DCs								
B4	*4.600 GW*	0.0	0.0	0.0	*4.600 GW*	53.8	2.4	0.2
B6	*6.500 GW*	0.2	0.1	0.0	*6.200 GW*	11.1	0.0	0.0
B7a	*7.600 GW*	0.7	0.4	0.0	*7.800 GW*	0.4	0.0	0.0
Other Eng & Wales	*n/a*	115.6	114.2	113.1	*n/a*	170.2	166.3	167.2
GB		**116.5**	**114.7**	**113.1**		**235.5**	**168.7**	**167.3**
Constraint price (£/MWh)		*82*	*82*	*82*		*79*	*79*	*80*
a+b+c_Incr & both DCs								
B4	*5.300 GW*	0.0	0.0	0.0	*5.300 GW*	12.4	0.0	0.0
B6	*7.600 GW*	0.1	0.0	0.0	*7.500 GW*	4.6	0.0	0.0
B7a	*7.600 GW*	0.7	0.4	0.0	*7.800 GW*	3.2	0.0	0.0
Other Eng & Wales	*n/a*	115.6	114.2	113.1	*n/a*	169.9	166.4	167.2
GB		**116.4**	**114.7**	**113.1**		**190.1**	**166.4**	**167.2**
Constraint price (£/MWh)		*82*	*82*	*82*		*79*	*80*	*80*

306. Not unexpectedly, we see that for all reinforcements constraint prices are highest in GG5c, which has the greatest volume of Scottish wind capacity. Most constraint prices are clustered in the range £80-90/MWh, which largely is a function of the difference between the Offer price of the

constrained-on plant (typically Marginal Gas or Marginal Coal, at £100/MWh and £120/MWh respectively) and the Bid price of constrained-off plant (typically Base Gas or Base Coal, at £10/MWh and £15/MWh respectively).

Discussion of GG5c 2015 Results

307. There are some important messages within these results by boundary. For example, considering the sequence of results by reinforcement for GG5c 2015:

- The *'current authorised'* base case sees large constraints of £399M (priced at £94/MWh) at the GB level; of these, £214M are on B6, and only £17M are on B7a. The £132M within-England is in fact on B15 'Thames Estuary export'.
- Case *a 'Incremental Reinforcements'* increases the winter B6 capability from 3.3 GW to 4.4 GW, and accordingly the B6 constraint comes down by £113M to £101M. However, the B7a capability remains limited to 5.0 GW, and B7a now increases in cost by £53M to £70M; ie. significant constraint costs have merely shifted one boundary South. GB constraints remain high at £311M.
- Case *b 'Huer-Dees DC'* more strongly reinforces both the B6 capability (4.9 GW) and the B7a capability (7.0 GW). This now removes most of the constraint, and GB total constraints have fallen to £155M, some 75% of which remains within England on the Thames Estuary.
- There is then little constraint case in 2015 for the further reinforcement of *a+b* together; only another £31M of constraint saving is seen, as GB constraints fall to £125M.
- Case *c 'Pehe-Hawp DC'* is interesting. It achieves the same increase as *b* in B6 capability, and although the new cable does not cross the B7a boundary, it improves the load-sharing across the boundary by directing power to the stronger Eastern side, away from the weaker Western side. The increase in B7a capability is from 5.0 GW to 5.6 GW – less than half the increase from *'Huer-Dees DC'*, and yet case *c* captures about four-fifths of the constraint reductions of case *b.* GB constraints are £198M.
- There is little constraint case for the further reinforcement *a+c* together; only as GB constraints remain some £201M. Additional reinforcement of B6 to 6.0 GW merely shifts the constraints to B7a.
- Cases *b+c* and *a+b+c* strongly reinforce B6 and B7a boundaries, and therefore these networks record the lowest overall GB constraints value (£116M). Large constraint costs remain on Thames Estuary.

Discussion of GG5c 2020 Results

308. There is a similar story, albeit more muted, within the corresponding sequence of results by reinforcement for GG5c 2020:

- The *'current authorised'* base case sees enormous GB constraints of £1,013M (priced at £95/MWh); of these, £466M are on B4, which with only a Beauly-Denny capability of 3.05 GW is inadequate for the volume of Northern Scottish Wind in this scenario.

- Case *a 'Incremental Reinforcements'* increases the B6 capability from 3.0 to 4.35 GW, and accordingly the B6 constraint almost halves from £343M to £190M. The B7a capability remains 5.2 GW and this boundary still sees negligible constraint costs. Overall GB constraints are £577M.
- Case *b 'Huer-Dees DC'* sees GB constraints comparable with case *a*, partly because the failure to improve B4 capability is offset by the benefit of reinforcing B6. GB constraints are high at £641M.
- Reinforcement of *a+b* together saves £656M on GB constraints (£358M). A large portion of this reduction is explained by the additional 1.55 GW capability on B6, which allows constraints to reduce by £180M compared with *a* alone.
- Case *c 'Pehe-Hawp DC'* sees GB constraints at £428M. The additional 1.55 GW of B4 capability means B4 constraints (£60M) are a huge £406M under the *'current authorised'* base case result, but some of the constraints have been moved one boundary South, as this reinforcement still sees high constraints on B6 (£169M).
- Reinforcement of *a+c* together saves £264M on GB constraints (£314M) compared with *a* alone. The additional 1.55 GW capability at B4 over case *a* is particularly effective, saving (£188M - £13M =) £175M alone.
- Reinforcement of *b+c* together saves £406M on GB constraints (£236M) compared with *b* alone. This reduction is principally the effect of the additional 1.55 GW reinforcement at B4.
- Case *a+b+c* records the lowest overall 2020 GB constraints value (£190M). Large constraints remain on Thames Estuary (£170M). Compared with *a+b* alone, constraints fall by £167M as a result of the additional reinforcement offered by the *'Pehe-Hawp' link.*

Constraint Cost Sensitivities for GG5c 2015 Current Authorised

309. The constraint costs results tabulated in Figure 12.10 depend heavily upon a set of modelling assumptions within our constraints model. Any of these assumptions taken in isolation has the potential to influence constraints costs to a significant degree.

310. To offer some indication of the uncertainty around the constraint forecasting process, Figure 12.11 shows a number of sensitivity results for the GG5c background in 2015 for the Base case *0_Curr_Auth.*

Figure 12.11: Constraint Cost Sensitivity for GG5c under 0_Curr_Auth

2015/16	GG5c Sensitivity	Constraints Cost £m	Delta Base Case	Constraints Price £/MWh
Reduced Constraints Costs	*500MW of operational (ie. "free") intertrip on B6 and B7a*	264	-34%	88
	Bid and Offer prices reduce to 70% of Base case values	280	-30%	66
	Zero boundary outage-weeks assumed for each summer	286	-28%	92
	Wind load factor reduced from 33% to 28%	292	-27%	84
	Half of Peterhead Base Gas (550MW) moves to Marginal Gas	305	-24%	91
Base Case 0_Curr_Auth		**399**	**n/a**	**94**
Increased Constraints Costs	*Assume 24 not 12 boundary outage-weeks each summer*	513	28%	95
	Wind load factor increased from 33% to 38%	538	35%	96
	Bid and Offer prices increase to 140% of Base case values	559	40%	131
	Longannet Marginal Coal (1152MW) remains at Base Coal	650	63%	90

311. Examining the sensitivities, the following broad groupings can be summarised:

Constraint costs 30% lower than Base case

312. The result that all Constraint costs are 30% lower than the Base case estimate arises directly in the sensitivity that all Bid and Offer prices are 70% of the Base case values. This result would arise more approximately, under sensitivities of the order of:
   - Zero boundary outage-weeks assumed for each summer;
   - Half of Peterhead capacity allocated to 'Base_Gas' moves to 'Marg-Gas' (a net movement of 550 MW);
   - Wind achieves 5% lower load factor than in the Base case (28% not 33%);
   - 500 MW of operational (ie. 'free') inter-trip assumed for B6 and B7a for all years.

Constraint costs 40% higher than Base case

313. Constraint costs 40% higher than the Base case arise directly in the sensitivity that all Bid and Offer prices are 140% of the Base case values. Once again, we can identify more sensitivities under which similar results arise:
   - 24, not 12, boundary outage-weeks assumed for each summer;
   - All, rather than half, of Longannet operates as 'Base_Coal' rather than 'Marg_Coal'[23] (a net movement of 1,152 MW);
   - Wind achieves 5% higher load factor than in the Base case (38% not 33%).

[23] Some would regard this as the case of Longannet 'gaming' its constrained-off position

Cost-Benefit Process

314. The detailed cost-benefit process is easiest illustrated by working through the exercise for one of the 33 cases (3 backgrounds x 11 comparisons) which we are studying in this report.

315. Consider the cost-benefit for network a 'Incremental Reinforcements' vs the 'Current Authorised' base case, in scenario GG5c. The cost-benefit (Figure 12.12) shows costs as positive and savings (benefits) as negative, and is built up as follows:

Figure 12.12: GG5c 'Incremental Reinforcements' over the base case (a. – 0.)

Year	T	OUT	O	L	Row Total
2010	156.3				**156.3**
2011	156.3				**156.3**
2012	156.3	58.5			**214.8**
2013	156.3	58.5			**214.8**
2014	0.0	0.0	-88.3	-12.0	**-100.3**
2015	0.0		-88.3	-12.0	**-100.3**
2016	-70.0		-157.9	-13.2	**-241.1**
2017			-227.5	-14.4	**-241.9**
2018			-297.0	-15.6	**-312.6**
2019			-366.6	-16.8	**-383.4**
2020			-436.2	-18.0	**-454.2**
2021			-436.2	-18.0	**-454.2**
2022			-436.2	-18.0	**-454.2**
2023			-436.2	-18.0	**-454.2**
2024			-436.2	-18.0	**-454.2**
2025			-436.2	-18.0	**-454.2**
2026			-436.2	-18.0	**-454.2**
2027			-436.2	-18.0	**-454.2**
2028			-436.2	-18.0	**-454.2**
2029			-436.2	-18.0	**-454.2**
Total	**555.0**	**117.0**	**-5,587.6**	**-264.0**	**-5,179.6**
6.25% TDR	**632.6**	**120.9**	**-3,042.7**	**-153.7**	**-2,442.8**
10% TDR	**686.1**	**123.5**	**-2,144.4**	**-113.8**	**-1,448.7**

- The reinforcement cost of £625M is incurred equally at £156M pa across 2010–2013. Advancement of asset replacement in 2016 (-£70M) reduces this to £555M.
- The total outage cost of £117M is split equally between 2012 and 2013.
- The constraints costs from the study are £399.2M for the *base case* in 2015, reducing to £310.9M against the *'Incremental Reinforcement'* capabilities. Hence a Constraint saving of £88.3M is entered against years 2014 and 2015. Likewise the constraint costs are £1,013.3M for the *base case* in 2020, reducing to £577.1M against the *'Incremental Reinforcement'* capabilities. Hence a Constraint saving of £436.2M is entered against years 2020–2029. For the intervening years 2016 to 2019, the constraint saving is phased linearly between the study results for 2015 and 2020.
- The Losses cost £529M for the *Base case* in 2015, and £517M for the *'Incremental Reinforcement'* network. Hence a Losses saving of £12M is entered against years 2014 and 2015. Likewise, a Losses saving of £18M is entered

against years 2020–2029. Again, results are phased across the intervening years 2016 to 2019.

- Finally, all these annual costs are present-valued back to a base year of 2013. Three test discount rates (TDR), of 0%, 6¼% and 10% are shown:
  - 0% is never taken seriously, but shows the simple addition of all costs, effectively ignoring the year in which they are incurred.
  - 6¼% is NGET's rate-of-return on transmission, and so is often applied as a test discount rate for investment appraisal.
  - 10% is a fairly high test discount rate, but is quoted because Constraints are highly variable costs, and it can be argued that one wants to pay back against future constraints quickly[24].

316. The overall conclusion in this case is that Constraint and Losses savings total -£5,852M, whereas Reinforcement and Outage costs total £672M. So at 0% TDR, there is an overall saving of £5,180M in proceeding with the Reinforcement.

317. At 10% TDR, there is still a strongly positive cost-benefit, but the overall saving is reduced to £1,449M, despite heavy discounting of constraint and losses savings in latter years, against the high up-front cost of the reinforcement.

Cost-Benefit Results

Cost-Benefits, by scenario

318. The cost benefit has been performed for 33 cases (ie. 3 scenarios against 11 network reinforcement differences).

319. The above results are now assessed across three scenarios, with the simple assumption that each scenario is equally probable. This is a very crude approximation, as there are many more generation background scenarios possible by 2015 and 2020 which meet HMG and EU renewable targets; nonetheless, our three scenarios capture a credible range of the most important variable, namely the balance of Wind generation between Scotland and England.[25]

[24] In passing, both the reinforcement costs and the constraint prices – and hence constraint costs – can be said to be in 2008 prices.

[25] In fact, we will consider the sensitivity that scenarios are not equally likely in section **0 Sensitivities (TDR 6¼%)**.

Figure 12.13: Cost Benefit by Scenario – TDR = 6.25% (£M)

Reinforcement(s)	Scenario	T	OUT	O	L	Total
a_Incr_Rein	*GG5c*	633	121	-3,043	-154	**-2,443**
against	*GG5b*	633	121	-1,184	-87	**-518**
0_Curr_Auth	*GG5a*	633	121	-545	-59	**150**
	wtd avg	***633***	***121***	***-1,591***	***-100***	***-937***
b_Huer-Dees DC	*GG5c*	735	0	-2,932	-253	**-2,450**
against	*GG5b*	735	0	-1,093	-151	**-508**
0_Curr_Auth	*GG5a*	735	0	-455	-113	**167**
	wtd avg	***735***	***0***	***-1,493***	***-173***	***-930***
a+b_Incr & Huer_DC	*GG5c*	735	0	-1,834	-253	**-1,352**
against	*GG5b*	735	0	-650	-151	**-66**
a_Incr_Rein	*GG5a*	735	0	-278	-113	**344**
	wtd avg	***735***	***0***	***-921***	***-173***	***-358***
c_Pehe-Hawp DC	*GG5c*	714	4	-4,169	-365	**-3,816**
against	*GG5b*	714	4	-1,651	-207	**-1,140**
0_Curr_Auth	*GG5a*	714	4	-762	-113	**-156**
	wtd avg	***714***	***4***	***-2,194***	***-228***	***-1,704***
a+c_Incr & Pehe_DC	*GG5c*	714	4	-1,927	-339	**-1,548**
against	*GG5b*	714	4	-606	-238	**-126**
a_Incr_Rein	*GG5a*	714	4	-256	-172	**291**
	wtd avg	***714***	***4***	***-930***	***-250***	***-461***
b+c_both_DCs	*GG5c*	714	4	-2,650	-236	**-2,167**
against	*GG5b*	714	4	-831	-172	**-285**
b_Huer-Dees DC	*GG5a*	714	4	-382	-116	**221**
	wtd avg	***714***	***4***	***-1,287***	***-175***	***-744***
a+b+c_Incr & both DCs	*GG5c*	714	4	-1,074	-175	**-530**
against	*GG5b*	714	4	-174	-168	**377**
a+b_Incr & Huer_DC	*GG5a*	714	4	-47	-139	**532**
	wtd avg	***714***	***4***	***-432***	***-161***	***126***
a+b_Incr & Huer_DC	*GG5c*	1,368	121	-4,877	-407	**-3,795**
against	*GG5b*	1,368	121	-1,835	-238	**-584**
0_Curr_Auth	*GG5a*	1,368	121	-823	-172	**494**
	wtd avg	***1,368***	***121***	***-2,512***	***-272***	***-1,295***
a+c_Incr & Pehe_DC	*GG5c*	1,347	125	-4,970	-493	**-3,991**
against	*GG5b*	1,347	125	-1,791	-325	**-644**
0_Curr_Auth	*GG5a*	1,347	125	-801	-230	**441**
	wtd avg	***1,347***	***125***	***-2,520***	***-349***	***-1,398***
b+c_both_DCs	*GG5c*	1,450	4	-5,582	-489	**-4,617**
against	*GG5b*	1,450	4	-1,924	-323	**-793**
0_Curr_Auth	*GG5a*	1,450	4	-837	-229	**388**
	wtd avg	***1,450***	***4***	***-2,781***	***-347***	***-1,674***
a+b+c_Incr & both DCs	*GG5c*	2,083	125	-5,951	-581	**-4,325**
against	*GG5b*	2,083	125	-2,009	-406	**-207**
0_Curr_Auth	*GG5a*	2,083	125	-870	-311	**1,026**
	wtd avg	***2,083***	***125***	***-2,943***	***-433***	***-1,169***
Test Discount Rate = 6.25%						

- Case *a. 'Incremental Reinforcements'* sees a consolidated cost-benefit of -£937M against the 6¼% TDR – £937M is greater than the discounted capital cost (£633M), hence we regard this cost-benefit as 'healthy'. Although this benefit is much reduced under 10% TDR to -£402M, the current justification of *'Incremental Reinforcements'* seems reasonably watertight.
- Case *b. 'Huer-Dees DC'* sees a consolidated cost-benefit of -£930M at 6¼% TDR and of -£476M at 10% TDR, and is thus well-justified by this central case assessment.
- Case *'a+b. against a.'*, namely the Huer-Dees DC link superimposed on Incremental Reinforcements, is reasonably cost-beneficial at 6¼% TDR, at a consolidated cost-benefit of -£358M.
- Case *c. 'Pehe-Hawp DC'* sees an even stronger consolidated cost-benefit of -£1,704M at 6¼% TDR and of -£1,005M at 10% TDR; this is because it addresses the B4 weaknesses, which are not yet properly considered within cases *a* and *b*.

- Case *'a+c. against a.'*, namely the Pehe-Hawp DC link superimposed on Incremental Reinforcements, is strongly cost-beneficial at 6¼% TDR, at a consolidated cost-benefit of -£1,373M.
- Case *'b+c. against b.'*, namely the Pehe-Hawp DC link superimposed on the Huer-Dees DC link, is strongly cost-beneficial at 6¼% TDR, at a consolidated cost-benefit of -£2,029M.
- Case *'a.+b.+c. against a.+b.'* is justified for 6¼% TDR (-£409M), but not at 10% (+£126M).
- Case *'a+b. against 0.'*, namely Incremental Reinforcements plus the Huer-Dees DC link, is highly cost-beneficial at 6¼% TDR, at a consolidated cost-benefit of -£1,295M.
- Case *'a+c. against 0.'*, namely Incremental Reinforcements plus the Pehe-Hawp DC link, is highly cost-beneficial at 6¼% TDR, at a consolidated cost-benefit of -£1,398M.
- Case *'b+c. against 0.'*, namely the Pehe-Hawp DC plus the Huer-Dees DC link, is strongly cost-beneficial at 6¼% TDR, at a consolidated cost-benefit of -£1,674M.
- Case *'a.+b.+c. against 0.'* assesses all three reinforcements against the Base case. It is justified for 6¼% TDR (-£1,169M) and even at 10% (-£141M).

Sensitivities (TDR 6¼%)

320. There are many sensitivities that can be performed on this cost-benefit. At present, we limit ourselves to just six, two for Transmission, two for Constraints, and one for scenario probability weighting, and one for the generation background. For simplicity, we will restrict analysis to TDR=6¼% throughout this section.

Transmission Costs +40%

321. This presents the consolidated cost-benefit, under the sensitivity that each network reinforcement costs 140% of the basic estimate of capital cost (eg. the Huer-Dees DC link costs £1,030M not £735M, post discounting). All other CBA elements are unchanged. The delta column shows the saving/cost of the sensitivity compared with the original result.

322. In terms of consolidated cost-benefits:

- there is still a clear-cut case for either *a., b.* or *c.* alone, although the overall benefit reduced by respectively £253M, £294M and £286M.
- the cases for *'a.+c. against a.'* and *'b.+c. against b.'* remain fairly strong, although the overall benefit reduces by £286M in both cases.
- the case for reinforcements *'a.+b. against a.'* and reduces markedly.
- reinforcement *'a.+b.+c. against a.+b.'* is clearly unjustified.
- the case for any pair of reinforcements (ie. *'a.+c. / 'b.+c. / 'a.+b. against 0.'*) remains very healthy
- the case for all three reinforcements (*'a.+b.+c. against 0.'*) becomes less strong.

Transmission Costs -30%

323. This presents the consolidated cost-benefit, under the sensitivity that each network reinforcement costs only 70% of the basic estimate of capital cost (eg. the Huer-Dees DC link costs £515M not £736M, post discounting). All other CBA elements are unchanged.

324. In terms of consolidated cost-benefits:

- with the exception of *'a.+b.+c. against a.+b.',* a strong case can be made for implementing all reinforcement options.
- *'a.+b.+c. against a.+b.'* appears to be a marginal decision.

Constraints -30%

325. This presents the consolidated cost-benefit, under the sensitivity that all Constraint costs are 70% of the base-case estimate. This result would arise directly, under the sensitivity that all Bid and Offer prices are 70% of the base case values. This result would arise more approximately, under sensitivities of the order of:
   - Zero boundary outage-weeks assumed for each summer;
   - Half of Peterhead moves from 'Base_Gas' to 'Marg-Gas' category;
   - Wind achieves 30% not 35% load factor;
   - 500 MW of operational (ie. 'free') inter-trip assumed for B6 and B7a for all years.

326. In terms of consolidated cost-benefits:

- there is still a case for any single and any pair of reinforcements (against the Base), despite large reductions in the overall benefits.
- the cases for reinforcements *'a.+b. against a.'* and *'a.+b.+c. against 0.'* are considerably weakened.
- the cases for reinforcement *'a.+b.+c. against 'a.+b'* is certainly not justified.

Constraints +40%

327. This presents the consolidated cost-benefit, under the sensitivity that all Constraint costs are 140% of the base-case estimate. This result would arise directly, under the sensitivity that all Bid and Offer prices are 140% of the base case values. As discussed in section 0, this result would arise more approximately, under sensitivities of the order of:
   - 24, not 12, boundary outage-weeks assumed for each summer;
   - All, rather than half, of Longannet operates at a 'Base_Coal' rather than a 'Marg-Coal' load factor;
   - Wind achieves 40% not 35% load factor.

328. In terms of consolidated cost-benefits:

- with the exception of '*a.+b.+c. against a.+b.',* which is marginal at best, a strong case can be made for implementing all reinforcement options.

Scenario Probability

329. So far in this report we have regarded the three GG5 background scenarios as equally probable, and have presented our scenario-weighted results accordingly. This is clearly a simplification, and we offer as a sensitivity the scenario probabilities in Figure12.14, which were derived through group consultation.

330. We suggest that GG5c is the least likely scenario, since it includes an ambitious target for onshore Scottish wind, and that GG5a is rather more likely, since it includes a more modest target.

Figure 12.14: Sensitivity: Revised Scenario Probabilities

Scenario	Scot Wind GW	Probability
GG5c	11.4	23%
GG5b	8.0	33%
GG5a	6.6	44%

331. Reducing the probability of a very high level of wind build in Scotland reduces constraints markedly – typically by 17-24% from the equal scenario probability case.
332. In terms of consolidated cost-benefit, all reinforcements remain healthy except *'a.+b.+c. against a.+b.'*, which moves further out of sight.

Generation background – nuclear life extension

333. It is quite possible that existing nuclear stations Hartlepool (1.2 GW) and Heysham 1 (1.2 GW) are granted life extensions past 2020. In this event, we can expect high constraint costs on the B7a boundary as a result of:
    - increased power flows from these baseload plant, and
    - a reduction of 200 MW (at least) in B7a boundary capabilities from the 2015 values.
334. To maintain the total plant capacity for 2020, we slip the commissioning of clean coal plant by two years, and so Kingsnorth SC (1.6 GW) and half of Tilbury SC (800 MW) commission post-2020. This has the effect of removing nearly all of the constraint costs marked as 'Other Eng & Wales', which are in fact constraints on the B15 boundary (Estuary). Since we dealing with delta constraint costs in this analysis, this is immaterial.
335. Some very large B7a 2020 constraint costs appear for all networks that do not strongly reinforce this boundary beyond 5.6 GW (e.g. the Pehe-Hawp DC link c. alone records £426M for GG5c). Even at 7.6 GW reinforcement (e.g. both DC links b.+c.) we see £70M of constraints.

Conclusions of the Cost Benefit Analysis

336. If there is certainty regarding the scenario that will evolve, then:

- Under GG5c (11.4 GW), all three reinforcements are justified, even at 10% test discount rate.
- Under GG5b (8.0 GW), then any pair of reinforcements are justified at 6¼%, but not at 10%, TDR. All three reinforcements are definitely not justified.
- Under GG5a (6.6 GW), then the only reinforcement that is justified is *c*. Eastern HVDC link alone, and even this is not quite justified at 10% TDR. This is because of the need to reinforce B4 out of SHETL. However, the sensitivity case of the nuclear power stations at Heysham and Hartlepool being granted life extensions beyond 2020 give healthy investment signals for the Western HVDC link.

337. The second premise is that there is equal probability of ⅓ : ⅓ : ⅓, that any one of the scenarios will evolve then:

- At 6¼% TDR, there is a strong case for proceeding with any pair of reinforcements. However, there is not quite a case for then proceeding with a third reinforcement.
- At 10% TDR, there is a marginal case for proceeding with any pair of reinforcements. There is no case then to proceed with a third reinforcement. The timing arguments of the reinforcements are interesting. There is a case to complete reinforcements *a*. Incremental and *b*. Western DC as soon as possible (which means by 2014), but there is only a justification to then proceed with *c*. Eastern DC in 2018.

338. Consideration of capital cost and constraint cost sensitivities at a 6.25%TDR and a weighted average of backgrounds demonstrates:

- A 40% increase in the capital cost of the reinforcements results in a justification to proceed with any two reinforcements, but not the third.
- A 30% decrease in the cost of constraints results a justification to proceed with any two reinforcements but the benefit is greatly reduced.

339. Thus the overall central conclusion is to proceed with two reinforcements, comprised of a. incremental and b. Western HVDC, to commission as soon as possible. There is only currently a cost-benefit case to proceed with c. Eastern DC by 2018, which means that decisions to commit to the full capital expenditure of the third reinforcement can be deferred until the generation background is more certain, probably for 1-3 years.

Chapter 13 - Conclusions

340. The predominant power flow on the GB transmission system is from north towards the south. In the north of Scotland, local demand is, for the most part, adequately met by the portfolio of hydro generation, Peterhead power station and an increasing number of wind farm developments. Accordingly, there is a predominant net export of energy from the region to the Central Belt of Scotland. Additional power flows in the Central Belt of Scotland, within the SPT network, place a severe strain on the 275 kV elements of the network and, in particular, the north to south and east to west power corridors.

341. The circuits between Scotland and England are already operating at their maximum capability, which is determined on the basis of voltage and stability considerations. Under all the generation scenarios considered, the transfers from Scotland to England increase significantly. Reinforcements identified to relieve the boundary restrictions across these circuits result in power transfers on the Upper North network of the England and Wales transmission system exceeding network capability. South of the Upper North boundary, the increased power flows south from Scotland and North West of England progressively diminish as they are offset by the closure and displacement of existing conventional generation along the way. Accordingly, while there are transmission overloads in northern England the effects are greatly muted as the flows travel towards the Midlands.

342. Offshore wind generation in England and Wales, together with the potential connection of new nuclear power stations raises a number of connection issues; particularly in Wales (North & Central), and the South West and along the English East Coast between the Humber and East Anglia. The increased power transfers across the North to Midlands boundary and/or the increased generation off the East Coast and/or Thames Estuary results in severe overloading of the northern transmission circuits securing London.

Analysis to Determine Transmission Reinforcement Requirements.

343. The range of potential power flows on the GB transmission system has been determined on the basis of the currently authorised GB transmission system (i.e. the existing GB transmission system together with all the approved transmission system reinforcements assumed to be in place for the years 2015 and 2020). Such authorised transmission reinforcements include:

- The Beauly – Denny 400 kV line, which is subject to a planning decision.
- The uprating of the transmission capacity between Scotland & England.

- The additional transmission capacity around the North West of England.

344. Even with a high level of assumed sharing, there is concern that due to the relative low utilisation of renewable intermittent generation together with the increased margin between installed generation capacity and demand, there may be opportunities for greater sharing of existing transmission capacity. A Fundamental Review of the GB SQSS and a Transmission Access Review (TAR) are currently being conducted. Whilst this report did not undertake analysis against all variants under consideration by these two reviews, a CBA was undertaken in respect of proposals to reinforce major system boundaries. The level of transmission capacity identified by the CBA should be consistent with the conclusion of both the Fundamental Review of the GB SQSS and the TAR, since it ensures that the GB transmission system is designed to give most economic and efficient solution Nevertheless, the proposals presented within this report will be subject to further examination in light of the conclusions of the two reviews.

345. Cost benefit analysis has been fully developed for all reinforcements from the central zone of the Scottish Hydro Electric Transmission (SHETL) system through the SP Transmission (SPT) system to the North of England (i.e. SYS boundaries B4, B6, B7(a), B8 etc). In undertaking a CBA the generation has been ranked as described in Annex A of this report. That is, generation has been grouped according to fuel type (e.g. nuclear, wind, large coal, modern gas etc.) and ranked in accordance with perceived likelihood of operation based on historic information covering the last few years. The generation constraint prices (i.e. bid on/off) are based on the average price seen over the last few years. Data in respect of the current year was not used as it is believed it contains a number of anomalies which would result in higher constraint cost if utilised in future constraint analysis over a long period. The cost of carbon is assumed to be included within the energy cost used in the study. Whilst this assumption is unlikely to have a material impact on the cost of future constraint cost, it is recognised that it likely to lead to an underestimation of the cost of losses in future years and, as a consequence, underestimate benefits of future transmission upgrades.

346. When identifying a shortfall in network capacity, consideration has been given to traditional solutions such as reconductoring circuits, upgrading to a higher voltage and constructing new lines. However, it is recognised that traditional methods of enhancing system capacity, particularly those which involve new overhead line routes, are becoming more difficult to achieve due to planning constraints and environmental concerns. Such difficulties can result in long delays in providing the required transmission capacity and consequential delays in facilitating the connection of sufficient volumes of renewable generation to meet UK targets. As a result, the TOs have investigated the potential for new or previously unused technologies on the GB transmission system in order to either: enhance and maximise the use of existing assets; or to provide new

infrastructure with minimal environmental impact and an acceptable level of technological risk. Discussions have been taking place with equipment manufacturers regarding the use of series compensation, HVDC technologies and developments in sub-sea cables.

Proposed Reinforcements

Within Scotland and Increased Capacity to England

347. With the Beauly-Denny 400 kV upgrade in place, further significant reinforcement of the north of Scotland transmission system can then be achieved by the strengthening of other elements of the system. This can be achieved by reconductoring and re-insulation work on existing tower routes, along with development of new substations or extensions to existing substations thus making maximum use of existing transmission routes and the installation of series compensation on existing circuits to maximise transfer capability on existing routes.

348. In the SHETL area, a first phase of upgrades will be required to reinforce the North-West of Scotland and transfer capability south to the Central Belt. This first phase will provide a system in the north of Scotland capable of accommodating 5.5 GW in the SHETL area of renewables (which is consistent with the 8 GW. The total cost of the reinforcement is £330M and the major elements of the reinforcements are summarised below:

Dounreay – Beauly – Kintore 275 kV upgrades (B1) -£180M
East coast reconductoring & re-insulation (B4) -£150M

349. A second phase of upgrades would be required to accommodate 6.9 GW of renewables in the north of Scotland, contributing to the total figure of 11.4 GW for Scotland. These upgrades comprise an additional £450M upgrade between Caithness & Moray together with the Eastern HVDC link described below. The requirement for these upgrades would be assessed as generation develops, but pre-construction work should commence at the earliest opportunity.

350. In respect of upgrading the main interconnected Scottish system from the north of Scotland to the Central Belt, and on to the north of England there are two main elements.

351. The ‘incremental’ upgrade, reconductoring and re-insulation work on existing tower routes, along with development of new substations or extensions to existing substations thus making maximum use of existing transmission routes and the installation of series compensation on existing circuits to maximise transfer capability on existing routes. The total cost of the reinforcements identified below is some £550M:

- SHTL East coast reconductoring & re-insulation (as above) - £150M

- SPT East Coast Upgrades, 400 kV double circuit operation - £135M
- SPT East West Upgrades -£80M
- SPT/NGET Series compensation on the circuits connecting the Scottish and English Networks - £160M
- NGET Reconductor Harker – Quernmore- £100M
- SPT onshore works for West Coast HVDC Link & HVDC Link - £400M
- NGET – Substation Works at Deeside & HVDC Link - £360M

352. The Eastern HVDC Link, a 1-2 GW HVDC between Peterhead and Hawthorne Pit. This provides additional capacity across B4, B5, B6 and limited support across boundary B7 (a). The total cost of the reinforcements is £700M and the major elements of the reinforcement are summarised below:

- SHETL onshore Substation works & Eastern HVDC Link - £340M
- NGET onshore Substation Works & Eastern HVDC Link - £360M

353. Whilst both reinforcements identified above are required by 2020 in the 11.4 GW scenario (based on the deterministic requirements of the GB SQSS and which is supported by the CBA), only two of the reinforcements would be required to accommodate 8 GW of renewable generation in Scotland. In determining which of the two reinforcement should be taken forward first, the CBA did not demonstrate conclusively that any two of the three solutions discussed above offered significant benefit over any other combination against the scenarios under consideration.

354. However, when considering the sensitivity of extending the life of the northern nuclear generation and/or when considering the benefits of the potential integration of the Eastern HVDC Link reinforcement into reinforcements required to accommodate higher volumes of renewable generation in the SHETL area (above that required to meet the 8 GW scenario), then the combination of the incremental reinforcement and the Western HVDC Link was demonstrated to be the most robust solution.

355. It is therefore proposed to proceed with the incremental upgrade and the Western HVDC Link immediately with a target completion date of 2015 at cost of £1255M and then with the Eastern interconector with a target completion date of 2018 at a cost of £700M.

North Wales – Stage 1

356. The scenarios assume that up to 4 GW of offshore wind farms in the southern Irish Sea may connect since the offshore generation in this area are expected to be the lowest cost Round 3 sites. Round 3 wind farms in

the area will compete for capacity with the existing pumped storage plant, Round 2 developments, interconnections to Ireland and new nuclear replanting at Wylfa. When total generation, whether wind or nuclear generation, on Wylfa exceeds 1.8 GW[26] in the area it will be necessary to construct a new circuit from Wylfa through to Pentir and establish the second circuit between Pentir and Trawsfyndd, together with some associated works further east. These works need to be undertaken in sequence and, in order to provide additional capacity by 2015, the engineering of some elements needs to commence early in 2009 if the programme is to be retained.

357. It will be necessary to seek consents for the new line, prior to the development of the offshore networks. Commitment to full construction can be adjusted as the build up of generation materialises. Potential savings in the costs of the offshore network in the region of £500M could be made by facilitating connections at Wylfa rather then a more remote site. The existing network in North Wales will accommodate a total of up to 3.5 GW of generation.

358. The proposed reinforcements will cost £400m and increase the capacity for completion by 2017.

Central Wales- Stage 1

359. New transmission assets including overhead line and cable sections need to be commissioned in order to connect the new generation to the transmission network. As the generation is made up of a number of small to medium wind farms the current proposal is to create a hub substation to which all wind farms input. A single transmission route will then be used to connect to the transmission network in the Legacy-Shrewsbury-Ironbridge circuits. Exact locations of both substation and transmission connection point are being evaluated.

360. The cost of these works above is estimated to be £225M for completion by 2015.

Combining North & Central Wales – Stage 2

361. The potential for further generation in Central Wales and significant new generation in the North Wales (Combination of Wind Generation and Nuclear on Wylfa) with the resulting pressure the north Wales boundary has highlighted an opportunity for considering a strategic development in central Wales. The capacity of the connection to the main interconnected system will frequently be under-utilised due to the typical load factor for wind generation. An additional connection from the Trawsfynydd area to the new substation in central Wales would allow full utilisation of this

[26] GB SQSS Review Group, Review Request GSR007, 'Review of Infeed Loss Limits' refers. GSR007 is considering raising the threshold limits to the normal (currently 1000 MW) and infrequent (currently 1320 MW) in recognition of the likelihood that single units in excess of 1320 MW (possibly posing a loss of power infeed risk of up to 1800 MW) connecting to the GB transmission system.

circuit and provide additional capacity across the north Wales boundary. Furthermore the by connecting further south than the Legacy-Shrewsbury-Ironbridge circuit, for example, Ironbridge or Bishop's Wood Substations, additional relief on heavily loaded circuits will be realised. Exploration of the transmission technology used is critical to making full strategic use of this new through route. This will be considered further in the next stage of the project.

English East Coast Reinforcement, Humber – Stage 1

362. Previously published investigations such as The Crown Estate 'Round 3 Offshore Wind Connection Study' and National Grid's input to the DECC Offshore Energy Strategic Environmental Assessment have considered a total of up to 12 GW of Round 3 offshore wind generation from the Dogger Bank and Hornsea areas connecting into the onshore transmission network in the Humber area. However, the 2020 Scenarios utilised in this study assume a maximum of between 4 and 8 GW by 2020 (dependent on the level of onshore wind assumed to arise in Scotland). The conclusions from this study propose to optimise both onshore and offshore transmission networks by integrating the design of these networks in order to capture significant cost savings (potentially in the range £200-300M). This can be achieved by connecting the earlier of the Round 3 wind farms in this region via direct tee connections into an onshore HVDC link connecting the Humber area to East Anglia.

363. In connecting these two areas, this solution affords the extra benefits of providing additional capacity for new generation connections to the north of the North to Midlands boundary as well as delaying, but not removing, the need for reinforcement in the East Anglia region. This comes as a result of the increased functionality of HVDC circuits and their superior controllability relative to standard AC overhead lines.

364. In view of the novel nature of this development, pre-engineering works will be required to ensure that the solution can be developed to required timescales. Otherwise, it may be necessary to develop an alternative solution, this negating the potential savings.

365. The cost of the onshore works required in order to achieve this is estimated to be £510M for completion by 2017.

English East Coast Reinforcement, East Anglia Stage 1

366. It is anticipated that between 3 and 4 GW of Round 3 offshore wind generation will materialise in waters directly east of East Anglia. The nearest onshore substations for connection are either Norwich Main or Sizewell, which are both located on the same 400 kV route. Therefore Round 3 offshore wind projects will clearly interact significantly with the potential for nuclear replanting at Sizewell of up to an additional 3.2 GW on this limited part of the network. Reinforcement of the network is

required for either offshore wind generation and/or nuclear replanting at Sizewell.

367. The reinforcements proposed for this area of the network include reconductoring the double circuit route from Walpole to Norwich and further south through Bramford, a new 400 kV substation at Bramford with all circuits from Norwich Main, Sizewell, Pelham and Rayleigh turned in and a new section of 400 kV double circuit overhead line, approximately 27 km in length from Bramford to the existing tee point down to Rayleigh (near Twinstead). This would create two double circuit routes to the west out of Bramford for completion by 2017.

368. The cost of onshore works above is estimated to be £400m, for completion in 2017.

English East Coast Reinforcements – Humber & East Anglia Stage 2

369. Should the volumes of offshore wind generation surpass the expected volumes of between 4 and 8 GW after 2020, new connections between Walpole and the Cottam – Eaton Socon line and/or Grimsby West and Keadby may be required; this is considered in the 2030 addendum report published alongside this report.

London – Stage 1

370. Historically, the network in and around London was developed to secure demand in the capital and its surroundings, when the major generation sources were the oil and coal fired plant in the Thames Estuary, or the coal-fired plant in the East and West Midlands. Additionally, it handled transfers to and from the interconnector at Sellindge.

371. However, several factors associated with the scenarios and sensitivities investigated, including the introduction of new low-carbon generation and liberalisation of European energy markets, drive a need for additional transmission capacity in the London area. Specifically increased generation in East Anglia and the Thames Estuary, increased interconnection with mainland Europe and the potential for future demand increases associated with the electrification of transport and/or the decarbonisation of space heat.

372. As a consequence there will be a need for additional transmission feeding central London from the north-east, and ultimately a need to reinforce east-west ties.

373. The proposed reinforcements are to reconductor the existing 400 kV circuits between Pelham and Waltham Cross to increase their capacity and uprate a 275 kV overhead line from Waltham Cross to Hackney via Brimsdown and Tottenham to 400 kV.

374. The cost of these works is estimated to be £190M with a completion date of 2015.

London - Stage 2

375. In the longer term, a section of the 'middle' 275 kV ring between Tilbury, Warley, Waltham Cross and Elstree would be uprated to 400 kV to provide additional capacity between the Estuary and North London. The cost of this additional work is estimated at £85M, with a notional completion date of 2022, subject to a future evaluation of need based on developments at that time.

South West

376. This area of the network, around the Severn Estuary, is characterised by large volumes of localised generation, high demand levels and a limited export capacity. Future changes in the generation connected in this region, including the potential for large amounts of gas fired generation and possible nuclear replanting at Hinkley Point and/or Oldbury-on-Severn, drive the need for additional transmission capacity. Planned offshore wind generation through future rounds of wind leasing in this area further add to this requirement.

377. Proposed reinforcements to accommodate the agreed 2020 scenario and sensitivities investigated include a new 400 kV circuit between Hinkley Point and Seabank of approximately 50 km in length. Reconductoring of existing circuits between Hinkley Point, Melksham and Bramley is also needed to provide the power generated in this area with a stronger electrical connection to the demand centre of London.

378. The cost of these works above is estimated to be £340M with a completion date of 2017.

Capex requirement

379. The total capex requirement to deliver the reinforcements identified above, the amount of generation which can be accommodated and the potential reduction in cost of delivering offshore networks is shown in the table below.

380. The provision of around 1.2 GW of connection capacity to the Scottish Islands and the linking of the Kintyre peninsula to Hunterston provide radial infeeds to the main interconnected system and is estimated at £1,090M. Whilst these reinforcements, which have been subject to separate consultation, have been optimised to ensure that the most economic and efficient design is taken forward in accordance with user requirements, with respect to the overhaul CBA, they have been treated in the same manner as offshore network costs, i.e they have not been included in the CBA.

Region	Reinforcement	Cost (£M)	Capacity of generation which can be accommodated (GW)			Potential saving in offshore network costs (£M)	Net costs (£M)
			Wind	Nuclear	Total		
Scotland – Stage 1, 2015	North of Scotland Upgrade Incremental Scottish Upgrade Western HVDC Link -	180 625 760	8	0	8	NA	1565
Scotland – Stage 2, 2018	North of Scotland Upgrade Eastern HVDC Link -	450 700	4	0	4	NA	1150
Wales – Stage 1	North Wales - 2017 Central Wales - 2015	350 225	4 – 6	0 – 3.3	4 – 9.3	500	75
English East Coast – Stage 1	Humberside East Anglia	510 400	7 – 11	0 – 3.3	7 – 14.2	350	560
London	London	190	1 – 2	-	1 – 2	-	190
South West	South West	340	2 – 3	3.3 – 3.3	5. 3 – 6.3	-	340
Total		4730	26 – 34	3.3 – 9.9	29.3 – 43.9	850	3880

381. Timely investment on the onshore network can provide significant benefits in facilitating the connection of offshore networks with a potential saving of £850M. However, it should be noted that many of the proposals involve the use of new and novel solutions and the integration of these solution into the existing transmission system need to be carefully engineered. If the transmission network is to facilitate the connection of renewable generation in a timely manner, it is essential that pre-construction work commence immediately. Recognising the use of new technology, it is difficult to determine the total cost of pre-construction engineering costs, but for schemes of this complexity it would be normal to anticipate costs in the range of 3-5% of total scheme costs, with typically 0.5-1% of cost occurring in year 1. For the package of schemes identified above, it is estimated that the preconstruction cost will be in the order of £150M with a cost of some £15M to £30M occurring in the first year.

Taking the Programme Forwards

382. Whilst the potential reinforcements are categorised into degree of confidence we have with regard need for proposed reinforcement, it is recognised that there is still a degree of uncertainty with regard volume and timing of generation in any given area. The generation volumes in the scenarios used in this report fall within the ranges considered by consultants engaged in similar work. Some sensitivity analysis around the scenarios has been undertaken to improve the robustness of the conclusions and recommendations. However, there remains a level of uncertainty about the development of generation, and its diversity, towards 2020. It is therefore proposed to continue to monitor the developments of the market and update the scenarios accordingly. The

proposed transmission reinforcement will be developed in such a manner as to ensure that the options are maintained at minimum cost, i.e undertaking pre construction engineering, and then taking beyond this stage when there is sufficient confidence that the proposed reinforcements will be required. This is the least regret solution, i.e it retains the ability to deliver to required timescales

383. In considering the schemes identified above, there is a very strong need case for the following which are considered most likely to be required:

- Dounreay – Beauly – Kintore 275 kV upgrades
- Incremental Scottish Upgrade
- Western HVDC Links
- North Wales Reinforcement
- Central Wales
- English East Coast - East Anglia
- London Stage 1

384. While the following also have a strong need case, there remains some uncertainty, with respect to their required completion dates:

- Eastern HVDC Link
- English East Coast – Humberside (HVDC link)
- South West
- London Stage 2

385. A number of other reinforcements have been identified in the report, but at this stage there is insufficient confidence to proceed with pre-construction engineering.

386. It is recommended that pre-construction engineering should commence immediately for all the schemes identified above, and whilst there is presently a very strong need case to progress, a full review will be undertaken towards completion of the pre-construction engineering to confirm required completion dates and hence the requirement to commit to construction.