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The Carbon Trust & DTI Renewables Network Impacts Study

Final Report

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Executive Summary

Introduction

This study was commissioned by the Carbon Trust and the DTI in June 2003 on behalf of the DTI's Renewables Advisory Board to assess the ability of the electricity networks to accommodate the Government's target to have 10% of electricity generated from renewable energy sources by 2010 and its aspiration to double that percentage by 2020.

The study is based on actual planned renewable generation projects and developers' business plans. Some scenario development was undertaken to show plausible ways in which the gap could be bridged in order to achieve the Government's 2010 target and its 2020 aspiration. The issues this raises for the development of the transmission and distribution systems are described below.

Objectives

The study's key objectives, as set by the Renewables Advisory Board, the Carbon Trust and DTI, are as follows:

- To undertake a forward renewables capacity mapping exercise derived from the generation companies' investment plans to 2010, and if the capacity mapping exercise indicates that the planned level of activity is unlikely to meet the 2010 target, to devise and consider a small number of scenarios whereby the 10% target could be achieved.
- To determine how the transmission and distribution networks need to evolve to enable the Government's 2010 target of 10% of electricity supplied from renewable sources and the aspiration to double that percentage.
- To investigate the network issues regarding the intermittent nature of renewable generation and the characterisation of renewable generation with regard to grid code compliance.
- To provide insights into the actions and the stepping stones required between now and 2020 for the key decisions and investments relating to the transformation of the transmission and distribution network, and those issues likely to affect the rate of progress toward the targets.

The study also analyses whether there are potential network impacts on renewables expansion from a simultaneous expansion of the UK's CHP capacity to meet the Government target of 10GW of CHP by 2010. The study's terms of reference were finalised in June 2003. It therefore has based its considerations on the then renewables targets as set down in the Energy White Paper. The majority of the research had been carried out and completed by the time the Government announced in November 2003 its decision to set a new target of 15% of renewables electricity sales by 2015 and to extend the Renewables Obligation to 2015. However, the impact of this important development in the stimulation of more renewables generation capacity is considered briefly as they impact on the key conclusions reported.

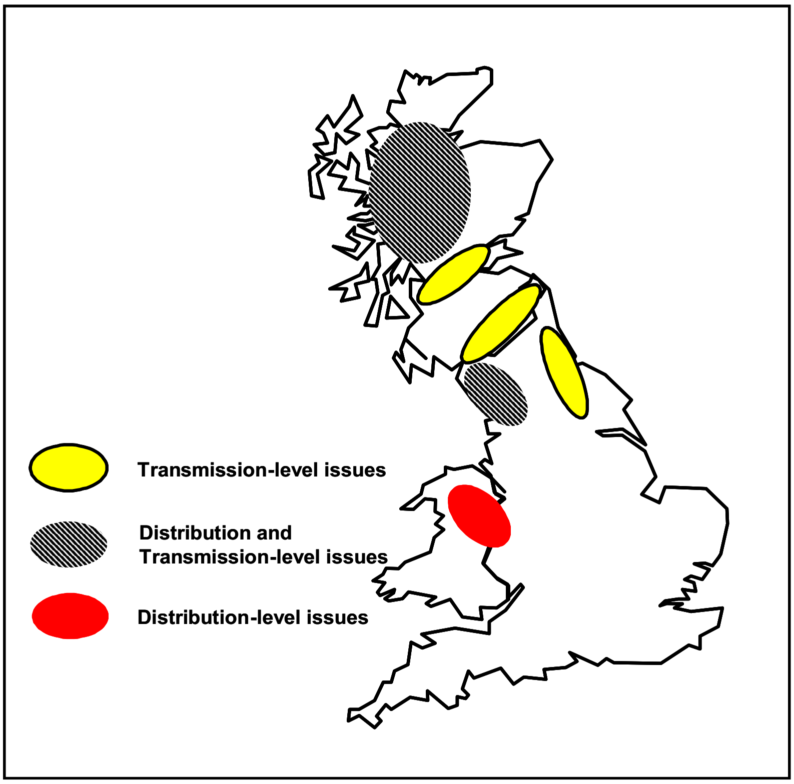
Conclusions

This study (which was largely completed ahead of the Government's announcement on extension of the Renewables Obligation Order to 2015, and the raising of the renewables target to 15% of electricity sales by 2015) has found that based on business plans, developers can meet about 72% of the 2010 target by 2006[1]. The Government's announcement has been welcomed by the renewables community and is expected to give added confidence to developers and investors that the Government is intent on creating a long term stable regime to incentivise investment in renewable energy technologies. However, in parallel with tackling what was a decline in investor confidence, is the need to tackle other significant barriers – in particular, planning uncertainty and the reinforcement of the transmission and distribution networks. This study has focused on the latter issues and concludes that:

Planning and Infrastructure Development

1. To satisfy the generators' plans and to comply fully with the 2010 target, major upgrades are required in the transmission and distribution networks in Scotland and in the North West of England (see Figure 0-1). This requires a high level of investment (in the order of £1.4bn to £2.1bn for transmission and £782m for distribution) and a speedy planning consent process in order to complete work well before 2010.

Figure 0-1: Location of Key System Capacity Constraints



[1] This date is based solely on current implementation timescales for actual projects under development and developers' own business plans.

The planning consents process is time constrained at present with time scales for permitting new high voltage lines presently taking up to 10 years. To ensure that generators' business plans and the 2010 target are achieved, the DTI and the Scottish Executive would need to accelerate the planning process on a national scale as a matter of urgency, taking into account that public perception of renewable power will play an important role in planning-related issues for both renewable power projects and the associated network reinforcement work.

The figure below indicates typical timescales for constructing new distribution and transmission lines.

Figure 0-2: Indicative Network Construction Times

Planning permission/Public Enquiry – 3 to 7 years depending on length and route of line and size of towers.	Design & Procurement – 1 year	Construction – 1 to 2 years+, depending on scale of project and ability to schedule system outages.

Overall timescale in the order of 5 to 10 years+, depending on size, location and complexity.

The levels of investment required to meet the generators' business plans and to meet the 2010 target are significantly higher than the capital investment allowed under the present price controls. For example, National Grid Transco (NGT) is presently allowed an annual capped expenditure of between £200M and £250M. This compares with £1.0bn to £1.4bn worth of upgrades required by 2006 to meet renewable generators' business plans. To ensure that the work is undertaken within the timescales required, Ofgem needs to finalise an adequate mechanism for selectively incentivising Transmission System Operators (TSOs) and Distribution System Operators (DNOs) as a matter of urgency. This mechanism has to stimulate the appropriate level of investment (both in volume and timing) and be regionally differentiated to ensure that local transmission and distribution 'hot spots' are adequately dealt with.

Infrastructure investment required to meet the Government's 2020 aspiration has been estimated at between £0.9bn and £1.1bn, in addition to the costs estimated for 2010. We recommend that further research is conducted into the use of an HVDC link along the west coast of the UK. Although costs are likely to be higher than for AC overhead lines for such an option, offshore HVDC could become more economically attractive if planning constraints became a serious source of delay for network expansion or impose significant amounts of undergrounding for network routes.

The incentive schemes devised for the TSOs and DNOs should allow a suitably long-term view for providing the necessary additional network capacity, including the possible future use of HVDC systems.

Intermittency

2. At the current target levels, intermittency is not a significant issue affecting the development of renewable generation. However, system balancing costs will increase as the penetration of intermittent renewables increases, and balancing costs could increase substantially with regard to meeting the 2020 aspirational target.

Impact of expansion of Combined Heat and Power

3. The expansion of CHP is not a significant issue affecting the developing of renewab le generation – ie CHP is not expected to use network capacity which otherwise could be available for renewables expansion. Our projection of CHP growth for 2010 is 74% of the CHP target. We believe this is a realistic figure, based on our own knowledge of current market conditions, discussions with the CHPA and other studies such as the work by Cambridge Econometrics.

Grid Code Compliance

4. Grid Code compliance could present a bottleneck to the achievement of the 2010 target, unless the TSOs provide temporary relaxation to fault ride-through requirements for new wind farms until a proven method of testing this capability can be developed, and until the critical penetration level of wind power onto the grid has been determined. This move by the TSOs must be followed by the manufacturers using the additional time this provides to gain sufficient operational experience with their new designs to enable grid code compliance guarantees to be provided. The network operators should provide clarity on the level of wind penetration at which provision of a fault ride-through capability becomes a critical network issue. Operational projects have addressed issues through direct negotiation with the system operators prior to finalising their grid connection agreements.

Interconnectivity of these issues

5. It is necessary to realise the inter-connectivity of these conclusions, for example resolving the planning issue without creating an adequate environment for investment will not result in the achievement of the 2010 target – and vice versa.

Recommended Further Studies

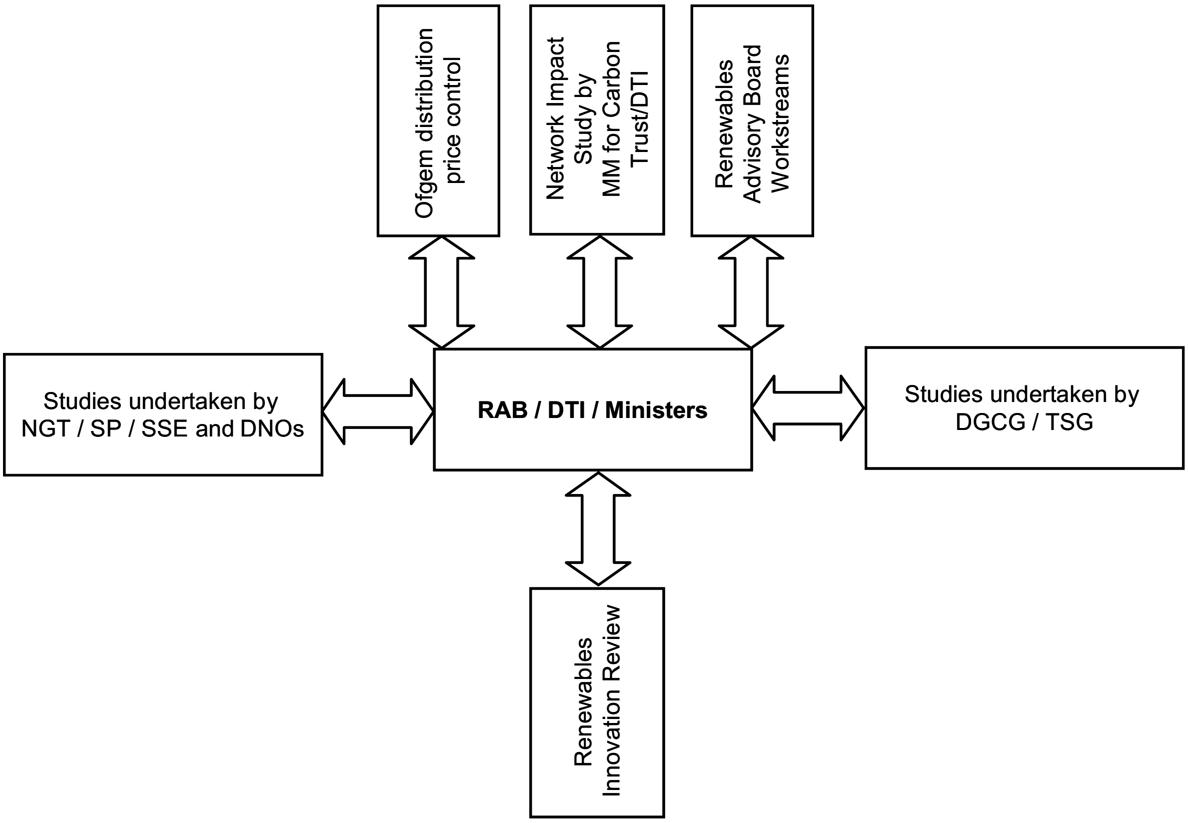
6. We recommend that studies to analyse complementary actions or alternatives to reinforcement of the networks should be carried out. These should include a cost-benefit analysis of the cost of constraining plant against the cost of network reinforcement to identify if a balance can be found between investing for new network capacity and constraining off wind power, particularly at times of low system demand. Such a cost benefit analysis should include an i nvestigation into the use of seasonally adjusted load factors for wind farms when considering network reinforcement requirements, in order to assist in identifying the optimum balance between network reinforcement and constraining renewable plant at times of low demand.

   It is also important that any further work investigates the effect of temporary network capacity reductions caused by the construction of new network components. In order to construct and commission new network sections it will be necessary to temporarily isolate existing sections of the networks for safety reasons, while work is undertaken.

Other Relevant Studies in train

This study seeks to complement and not cut across or duplicate work being undertaken by other entities. The study team has therefore consulted widely, through the study Advisory Group and directly with stakeholders. This work offers analysis on the issues likely to influence renewable expansion by taking into consideration real projects and the perspective of project devel opers. The outcomes from this study need to be placed in the context of other related studies (see Figure 0-3).

Figure 0-3: Study's Context



Responsibilities and Timeline for Action

The responsibilities, key actions and associated timeline are summarised below in Figure 0-4. The following page summarises our key findings within a single table.

Figure 0-4: Actions and Timeline

Generators' Business Plans	Scenarios	White Paper Timelines

2003 **2004** **2010** **2020**

Actions needed to deliver the Developers' Business Plans

- To achieve the generators' business plans, DTI/ Scottish Execut ive must facilitate planning consents for the necessary transmission reinforcements to start construction in 2 004. (This will be extremely difficult).
- To ensure generators' business plans are met, Scottish Executiv e must facilitate planning consents for the necessary distribution reinforcements to be available from 2004/ 2005 onwards according to specific generators' needs.
- To ensure that business plans and the 2010 target are met, TSOs to confirm the necessary reinforcements, develop projects and be ready to start construction and upgrade transmission assets for connecting plants from 2006 onwards.
- To avoid delays in meeting generators' business plans and the 2 010 target, DNOs to be ready to construct strategic reinforcements commencing 2004/2005.
- To avoid delays, Ofgem to finalise an adequate incentive mechanism for TSOs to invest in the necessary assets.
- Ofgem to finalise proposed means to incentivise DNOs to invest in the necessary assets.
- TSOs and wind turbines manufacturers to agree in a FRT testing proce dure.
- Planning authorities to modify their planning procedures in acc ordance with the Government's Draft Planning Policy Statement
- DTI/Scottish Executive to ensure planning authorities identify land use zoning for renewable energy.
- MoD to engage positively and minimise negative impact on projec ts.
- To achieve 2010 targets Carbon Trust/ DTI to ensure that the re levant conclusions from this report are acted upon.
- Carbon Trust/DTI to commission further research into intermitte ncy.

Actions needed to deliver the scenarios to 2010:

- TSOs should temporarily relax FRT grid code requirements until wind penetration levels increase.
- To achieve full compliance with the 2010 target, The DTI/Scotti sh Executive must facilitate planning consents for the necessary transmission reinforcements post 2004.
- To achieve full compliance with the 2010 target, The DTI/Scotti sh Executive to make sure that planning consents for distribution work post 2004 are made avail able as necessary.
- DTI/Carbon Trust to commission further investigation into HVDC links as alternatives to transmission reinforcement.
- A cost-benefit analysis should be carried out to identify an acceptable balance between network costs and plant constraints.

Actions needed to deliver the scenarios to 2020

- The TSOs need to identify the strategic investments required and set planning activities in motion by 2010.
- The DTI/Scottish Executive must facilitate planning consents fo r the necessary distribution reinforcements post 2010.
- DNOs to identify projects for 2020 and set planning procedures in motion.
- The DTI/Scottish Executive must facilitate planning consents fo r the necessary transmission reinforcements post 2010.

Key Findings for 72% of the 2010 Target

Not a significant issue	Significant Issue
• Intermittency • CHP expansion	• **Project development**: there is a need to change 'business as usual', i.e. increased stimulation is needed to ensure capacity additions. • **Transmission**: significant levels of reinforcement and new build required in Scotland and the Scottish Interconnector (in the order of £1.0bn to £1.4bn). This requires the planning process to be speeded-up to obtain resolution of planning consents to start construction in 2004. It also requires a mechanism to incentivise investment. Timing is crucial. • **Distribution**: there are very significant bottlenecks in Scotland (costs in the order of £385m). This requires an incentive mechanism. Construction needs to start in 2004/2005, planning may be an issue due to the scale of the development required. Timing is crucial. • **Grid Code Compliance**: could present a bottleneck to the achievement of the 2010 target, unless the TSOs provide temporary relaxation to fault ride-through requirements for new wind farms. Manufacturers should use the time this provides to gain sufficient operational experience with their new designs to enable grid code compliance guarantees to be provided.

Key Findings for the 2010 Target

Not a significant issue	Significant Issue
• Grid Code Compliance (subject to progress on satisfactory resolution) • Intermittency • CHP expansion to 74% of the 2010 CHP target	• **Transmission:** In the period 2006-2010 there are significant levels of reinforcement and new build required in Scotland, the Scottish-English Interconnector and in the North West of England. The incremental cost is in the order of £0.4bn to £0.7bn, depending on the renewable scenario, to give a total cost for full 2010 compliance of £1.4bn to £2.1bn. Investment and planning remain potential bottlenecks particularly if these are not resolved for 2006. Further investigation of HVDC links is recommended. • **Distribution:** There is significant new build required in Scotland with costs rising to £20-138m. Also, significant reinforcements are required in the North West of England and relatively modest in Wales. The total costs are likely to be in the order of £201-265m. Investment will remain an issue if this is not resolved for 2006.

Key Findings for the 2020 Aspirational Target

Not a significant issue	Significant Issue

• Grid Code Compliance
 	
(subject to progress on satisfactory resolution)
	• **Intermittency:** Balancing costs become more expensive as intermittent generation levels increase beyond 2010.
	• **Transmission:** Further reinforcements are needed in Scotland, the Scottish-English Interconnector and in England. The cost is in the order of £0.9bn to £1.1bn, in addition to the 2010 costs.
	• **Distribution:** reinforcements are needed in the following areas:
	    • Midlands and South of England: relatively modest with extra costs in the order of £33m -117m.
	    • North of England and Wales: significant reinforcements. Further cost likely to be in the order of £507 -782m.
	    • Scotland: relatively modest reinforcements due to the work carried out for the 2010 target. Likely extra costs in the order of £111-120m.
	
	Adequate incentives have to be in place and planning needs to be set in motion in 2010.

1 Introduction and Key Conclusions

Customers for the study

This study was commissioned by the Carbon Trust and the DTI in June 2003 on behalf of the DTI's Renewables Advisory Board. All main aspects have been discussed with the study's Advisory Group set up by the Carbon Trust and the DTI and comprising representatives from:

- Ofgem
- the Renewable Power Association (RPA)
- the British Wind Energy Association (BWEA)
- the Distribution Network Operators (DNOs)
- the Technical Steering Group (TSG) of the Distributed Generation and Co-ordination Group (DGCC).

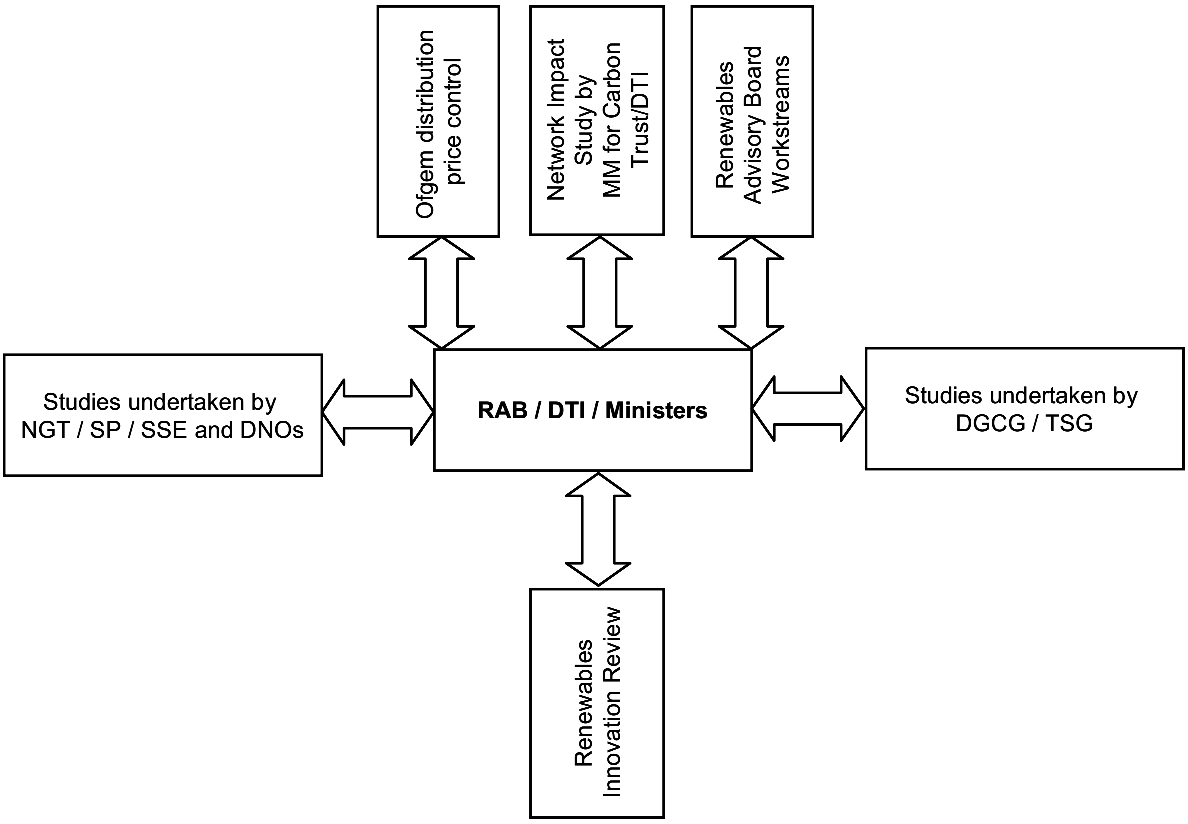
This report summarises the study findings with the full details of all elements of the work contained in the following annexes:

- Annex 1: Capacity Mapping & Market Scenarios for 2010 and 2020
- Annex 2: Transmission Network Topography Analysis
- Annex 3: Distribution Network Topography Analysis
- Annex 4: Intermittency
- Annex 5: Grid Code Compliance.

Other Studies

This study seeks to complement and not cut across or duplicate work being undertaken by other entities. The study team has therefore consulted widely, through the study Advisory Group and directly with stakeholders. This work offers analysis on the issues likely to influence renewable expansion by taking into consideration real projects and the perspective of project developers. The outcomes from this study need to be placed in the context of other studies (see Figure 1-1).

Figure 1-1: Study's Context



Key Findings for 72% of the 2010 Target

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Key Findings for the 2010 Target

Not a significant issue	Significant Issue
• Grid Code Compliance (subject to progress on satisfactory resolution) • Intermittency • CHP expansion to 74% of the 2010 CHP target	• **Transmission:** In the period 2006-2010 there are significant levels of reinforcement and new build required in Scotland, the Scottish-English Interconnector and in the North West of England. The incremental cost is in the order of £0.4bn to £0.7bn, depending on the renewable scenario, to give a total cost for full 2010 compliance of £1.4bn to £2.1bn. Investment and planning remain potential bottlenecks partic ularly if these are not resolved for 2006. Further investigation of HVDC links is recommended. • **Distribution:** There is significant new build required in Scotland with costs rising to £20 -138m. Also, significant reinforcements are required in the North West of England and relatively modest in Wales. The total costs are likely to be in the order of £201-265m. Investment will remain an issue if this is not resolved for 2006.

Key Findings for the 2020 Aspirational Target

Not a significant issue	Significant Issue

• Grid Code Compliance
 	
(subject to progress on satisfactory resolution)
	• **Intermittency:** Balancing costs become more expensive as intermittent generation levels increase beyond 2010.
	• **Transmission:** Further reinforcements are needed in Scotland, the Scottis h-English Interconnector and in England. The cost is in the order of £0.9bn to £1.1bn, in addition to the 2010 costs.
	• **Distribution:** reinforcements are needed in the following areas:
	    • Midlands and South of England: relatively modest with extra costs in th e order of £33m-117m.
	    • North of England and Wales: significant reinforcements. Further cost likely to be in the order of £507 -782m.
	    • Scotland: relatively modest reinforcements due to the work carried out for the 2010 target. Likely extra costs in the order of £111-120m.
	
	Adequate incentives have to be in place and planning needs to be set in motion in 2010.

2 Generation: Known Projects and Scenarios

Introduction

This study follows a "bottom up" approach to build up renewable power capacity on the network s by taking information provided by project developers on actual projects and longer -term business plans.[1]

This approach makes this study distinctive as it allows analysis of the impact of actual and highly likely developments, lowering the reliance on sce narios and projections.

Methodology

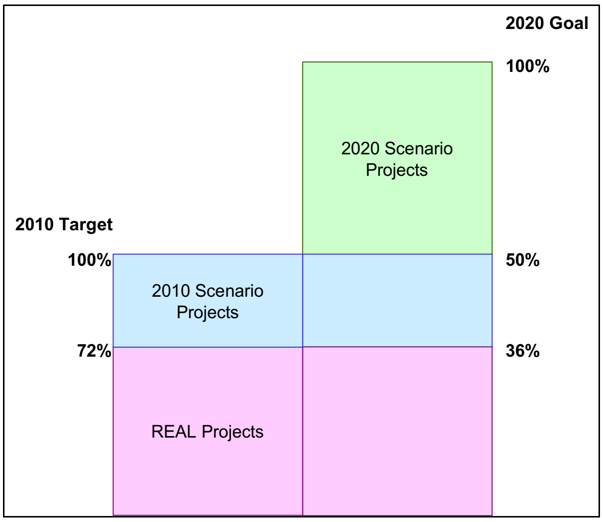
An extensive exercise was undertaken to identify known renewable and CHP projects. Information was obtained from the following sources:

- BWEA database on wind projects
- Power UK's tracker database on power project developm ent in the UK
- The Land Use Consultant's database provided by AEA Technology
- Discussions with 18 major project developers, who between them represent approximately 85% of operational and planned projects identified by the study.

Scenarios were developed to make-up the renewable generation capacity to allow full compliance with the 2010 and 2020 targets. Figure 2-1 shows how capacity has been built-up. Our scenarios have been constructed on the basis of the real projects and actual b usiness plans of developers. They do not consider other scenario possibilities, for example developing a scenario based on optimising generation and network investments. It is conceivable that a lower overall investment would be required if scenarios were constructed on the basis of minimising overall investment. However such an approach would not reflect actual project development activity and developers' business plans, with the risk that the scenarios would not realistically reflect the current develo pment trends within the UK. Our work has shown very clearly that until at least 2006 the majority of renewable power development will focus on the north of England and Scotland, with wind power making up the bulk of generation capacity.

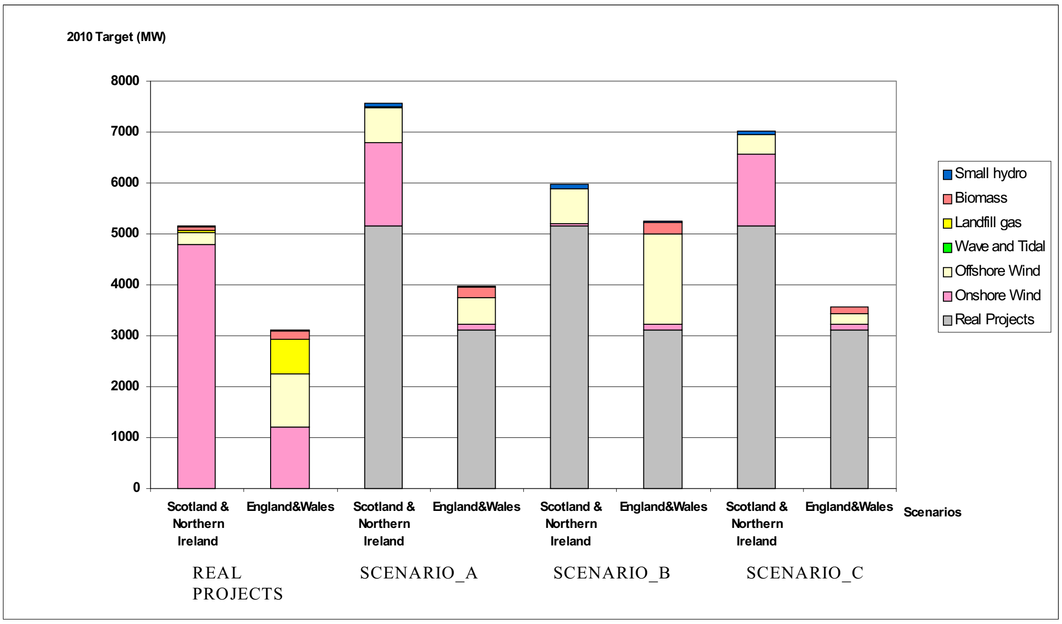
[1] Full details on the capacity mapping exercise and the 2010 and 2020 scenarios are contained in Annex 1 of this study.

Figure 2-1: Capacity Build-up



The technology mix and location of renewable projects in the 2010 scenarios are based on developers' longer-term business plans. For the period to 2020 scenarios have been based on the Energy White Paper timelines. The resulting scenarios are summarised in Figure 2-2 and Figure 2-3 respectively. The capacity factors of each different technology have been applied to these figures. The grey area s indicated on the bars for Scenarios A, B and C indicate the level of real project data to which scenario projects were added to reach the 2010 target and 2020 aspirational target generation levels. The graphs below therefore also indicate how the use of scenario projections was kept to a minimum.

Figure 2-2: 2010 Scenarios

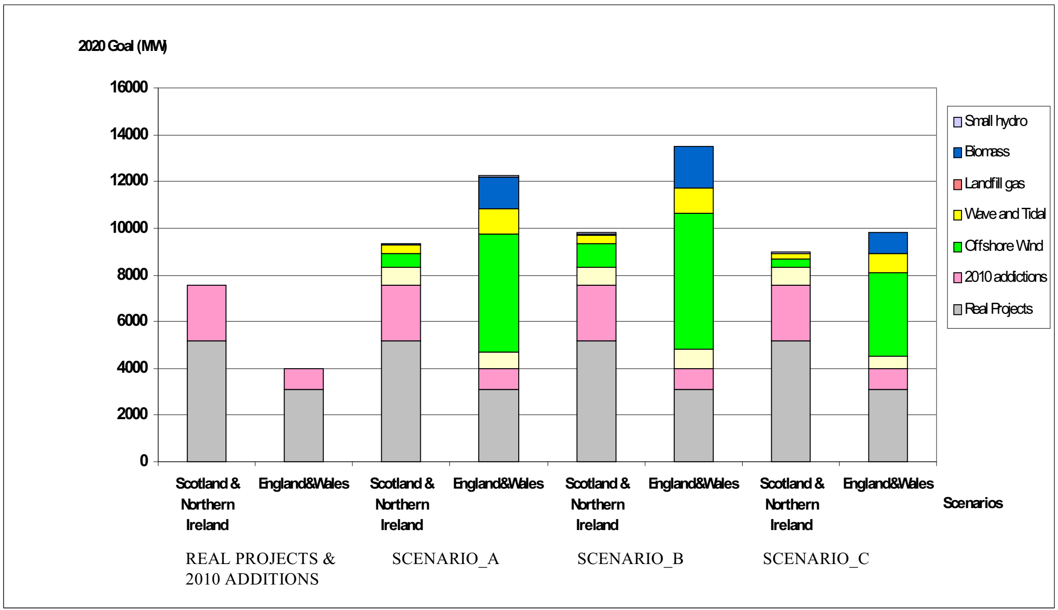


2010 Scenario A= High Scottish Onshore Wind

2010 Scenario B= High English Offshore Wind

2010 Scenario C= Demand sensitivity with High Scottish Onshore Wind

Figure 2-3: 2020 Scenarios



2020 Scenario A= Base demand

2020 Scenario B= High demand

2020 Scenario C= Low demand

The regional location of real projects and those derived for each sce nario is contained in Annex 1. This also indicates the amount of capacity connected to the transmission or distribution networks.

The scenarios are also informed by other studies (see

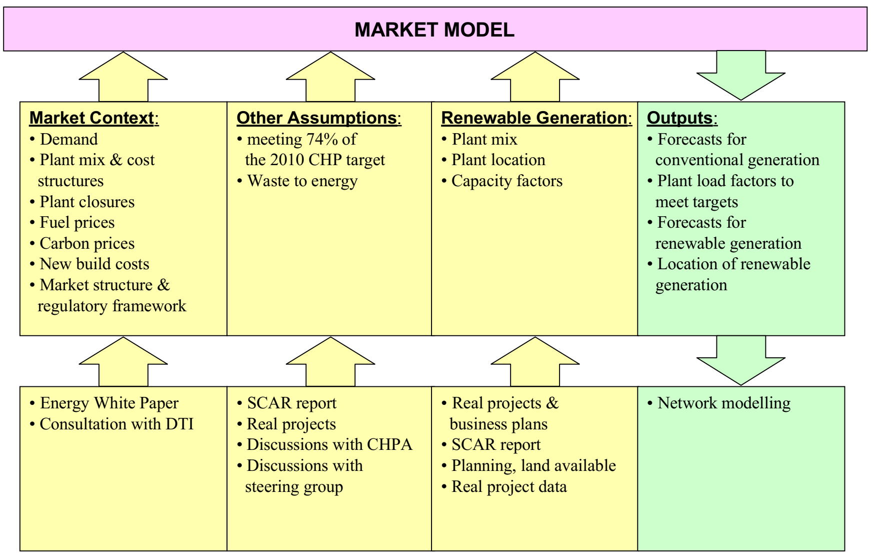
Table 2-1).

Table 2-1: Mott MacDonald's Scenarios in Context with other Studies

	MM	Ilex	Oxera/ Tyndall	Comments
Expected electricity sales by UK suppliers (TWh)	343.6	394	324.2	Tyndall and Oxera reports are based on the document "New and Renewable Energy" August 2001 DTI. Ilex is based on system demand. MM assumptions take into account that sales in 2002 were 320TWh and growth at 0.9% per year.
Target (10%) (TWh)	35.7 (10.4%)	39.4	32.4	Tyndall and Oxera work in the range of 21.3TWh and 32.3TWh as two different scenarios.
Real Projects	72%	?	-	MM scenarios are based mainly in real projects while none of the other reports account for real projects. Oxera and Tyndall's reports are capacity assessments. Ilex's report although use real projects does not mention in which proportion.
CHP	74% of target	76-80% of target		Developments currently stalled. Low spark spreads and high imbalance penalties will constrain expansion until second half of decade. MM estimations are in line with Ilex
Average Capacity Factors				MM based on Ilex, BWEA and industry expertise
Onshore wind	28%	30%		
Offshore wind	37%	36-39%		
Biomass	65%	66%		

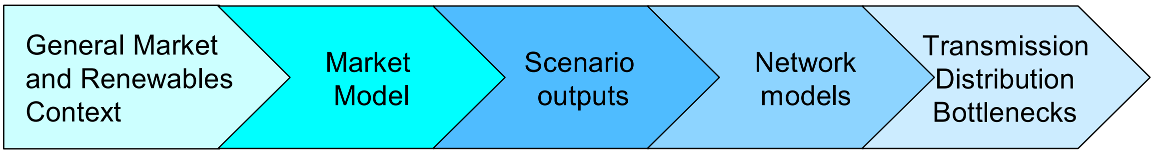
All scenarios are modelled to forecast plant operating regimes. The principles of the market model are summarised in Figure 2-4.

Figure 2-4: Scenario Modelling



The outputs from the market model for each scenario are used to assess the impact of increasing renewable generation on the transmission and distribution networks. See Figure 2-5.

Figure 2-5: Information Flows



Key Findings

Generators' business plans make-up 72% of the 2010 target and take real capacity up to 2006 (2008 for offshore wind), based on the developers' own implementation dates.

Developers' current business plans make up 72% of the 2010 target in the following way:

- 33% of the 2010 target is made up by projects very likely to go ahead. These include those with planning permission and those in the application phase in areas with a high chance of achieving planning permission.
- A further 39% of the 2010 target is made-up by projects likely to go ahead. These include those that have not applied for planning permission but that have a reasonable chance of going ahead (greater than 50%) due to their size and location.

Most of the real projects contained in generators' business plans have implementation dates before 2006. Business plans for the later part of the period (2006-2010) are not project or location specific and they are much less certain. This is because the planning horizon of project developers does not consider more than three years ahead in any detail.

Reaching 72% of the 2010 target needs a change to business as usual and the recent Government decision to extend the RO target to 15% of the UK's electricity sales by 2015 represents the type of further effort required to provide the level of developer confidence needed to achieve full compliance with the 2010 target.

Achieving 72% of the 2010 requires a change to business as usual, particularly in the planning procedures for generation and network capacity issues for both transmission and distribution. This is because at present generators' business plans are affected by the lack of certainty over the planning permission process which can be slow for new generators, and there are issues relating the availability of transmission and distribution capacity and grid connection costs.

The recent announcement by Government of an increase in the Renewable Obligation from 10% by 2010 to 15% by 2015 removes a considerable degree of uncertainty over ROCs and addresses one of the key issues affecting renewable project development. However, significant concerns remain in relation to planning procedures and timescales for resolution of generation and network capacity issues for both transmission and distribution networks.

Given removal of the constraints to achieve the generators' business plans to 2006, achievement of the 2010 target appears possible. Nevertheless, further effort is needed to ensure that the planning issues regarding transmission and distribution that may constraint achievement of the 2010 target are resolved quickly.

Actions

Action 1	The current planning process delays renewable generation development and it will inhibit the achievement of the 2010 target. Planning authorities need to modify their planning procedures in accordance with the Government's Draft Planning Policy Statement.
Action 2	Planning restrictions also stem from objections placed by the MoD to renewable generation development. To enable the 2010 target to be met the MoD needs to engage positively and minimise negative impact on projects.
Action 3	Achievement of the 2010 target requires grid connection issues to be resolved quickly. To ensure that the transmission and distribution capacity required for the expansion is available, the Carbon Trust and the DTI need to ensure that the relevant conclusions from this reports are acted upon.

Action on these key issues needs to be taken now.

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3 Network Development Needs: Transmission

Introduction

This section presents a summary of the effects on the transmission network of increasing levels of renewable generation to meet the generators' business plans and the governments' 2010 target and 2020 aspirational goal. It also analyses any potential impact of a simultaneous achievement of 74% of the CHP 2010 target.[1]

Historically, there has been a large North to South power flow across the electricity transmission system in England and Wales, from the large generating stations in the North of England and Scotland to the main load centres in the South East of England.

In order to utilise the substantial renewable energy resource in the north of England and in Scotland, these power flows are likely to increase. Additional resources are also available via offshore wind, mainly off the English and Welsh coasts.

The assessment presented below quantifies these expected increases in the North to South power flow, and identifies the likely level of transmission reinforcement required.

Methodology

The transmission network is modelled for increasing amounts of renewable generation in the following steps:

- Step One: this maps very likely projects onto the transmission network (33% of the 2010 target)
- Step Two: this steps adds projects that are likely to go ahead (a further 39% of the 2010 target) to the network
- Step Three: this step maps the longer term business plans, the CHP projects currently on hold and the projects derived from the study's own 2010 and 2020 scenarios.

The model assesses the impact of projects connected directly to the transmission network and also the impact on the transmission network of increasing renewable and CHP generation connected to the distribution networks. We have only assessed thermal and voltage parameters as the information required to assess other transmission system parameters is not within the public domain.

For each case, a high level assessment is carried out on the system to assess the likely flows across the major transmission boundaries, based on the level of generation and load within each the generation tariff zones. Where the generation in a zone is greater than the load, the zone is considered to have a net export of power, if the load in a zone is greater than the generation, the zone is considered to have a net import of power.

[1] Full details are included in Annex 2 of this study.

In order to assess the likely need for reinforcement, the level of power flow predicted by the high level assessment is compared with the total thermal rating of the lines crossing the zonal boundaries. This is then analysed in more detail with a system model built using the commercially available PSS/E software package.

In accordance with NGT's security and quality of supply standards, the capacity of the zonal boundaries is considered with the worst case double circuit outage.

Our cost estimates include equipment and installation costs and an additional 15% contingency for other project engineering costs. Our estimates assume an unconstrained ability to construct the required reinforcements and based on our experience there is a high probability of cost escalation. Further more, we expect there to be a contractors' skills constraint, given the volume of work required and the timescales involved. As well as the potential impact such a constraint would have on costs, there is also a potential impact on the rate at which work could be completed.

Key Findings

Achievement of Generator's Business Plans

Major reinforcements are needed in Scotland and in the Scottish-English interconnector by 2006 to satisfy generators' business plans and to meet 72% of the 2010 target. These are likely to cost in the order of £1.0bn to £1.4bn. This is a significant bottleneck under the present regulatory framework.

To meet the 2006 generators' business plans and thus reach 72% of the 2010 target, the following areas need reinforcing or expanding:

- Within SSE's transmission system
- The interconnection between the SSE and Scottish Power systems
- Within Scottish Power's transmission system
- The Scotland-England interconnector
- The northern components of NGT's system which feed into the Interconnector
- Upgrade of the Cumbria ring to transmission level (depends heavily on generation development local to this area)

As indicated above, the total cost of reinforcements to meet 72% of the target is in the order of £1.0bn to £1.4bn. This is a significant bottleneck within the present regulatory system. Currently, £250m as an average per year of capital expenditure is allowed by Ofgem. This cap covers renewal of existing assets and new connections and it is insufficient to cover the level of investment required. To ensure that the work is undertaken within the timescales required, Ofgem needs to finalise an adequate mechanism for incentivising the TSOs that provides the right level of investment and that is regionally differentiated to reflect the location of the transmission 'hot spots'.

To reach 72% of the target based on generators' business plans, urgent resolution of transmission related planning issues is required to start construction of new transmission circuits in 2004.

The reinforcements identified above involve the construction of new overhead transmission circuits. This has serious timing implications because to allow the connection of the generators planned for 2006, construction of these new circuits needs to start by 2004.

The present planning process is a very significant bottleneck. Typical construction times for new transmission lines are around two years but obtaining planning consents can take up to 10 years. The most recent lines built (one in Scotland and one in England) have taken 11 and 13 years from conception to commissioning due to planning consent delays.

Achieving the generators' business plans requires urgent resolution of planning issues at a national level and this will be extremely difficult to achieve within the present planning process. Given the volume of work required, and the associated timescales, availability of sufficient skilled personnel may also become a potential constraint on the rate of network reinforcement.

If there is no action to accelerate the planning process, it is estimated that only 50 to 60% of the business plan capacity going forward might be connectable to the network before generating constraints became severe. There is an urgent task ahead to identify the key causes of the historic delays and to create the same degree of Ministerial commitment to address these causes – in the same way they moved quickly to address the developer investment uncertainty attributed to ROCs uncertainty post-2010.

Sufficient developer activity is present, especially given the extension of the RO target to 15% by 2015, and the System Operators are already aware of the actions which they must take. However, there remain major planning and investment incentive barriers. These have to be resolved by DTI/ODPM and Ofgem for the System Operators to be able to tackle the network reinforcement works and allow the developers to successfully complete the level of projects needed to reach the 2010 target.

Full Compliance with the 2010 Target

Further reinforcements are needed in Scotland, the Scottish-English Interconnector and in the North West of England to allow 100% compliance with the 2010 target. These reinforcements are likely to costs in the order of £0.4bn to £0.7bn giving a cumulative total of £1.4bn to £2.1bn. The new incentive mechanism needs to allow for this investment to take place otherwise this will remain a significant bottleneck.

Further reinforcements are needed in Scotland and in the Scottish -England interconnector to meet the 2010 target. These are likely to be required in the following locations:

- Within SSE's transmission system
- The interconnection between the SSE and ScottishPower systems

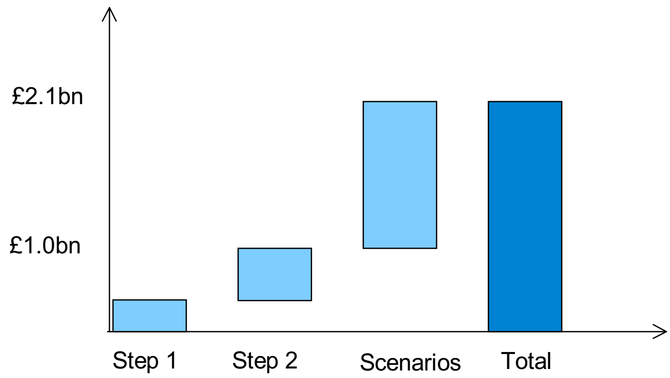
- Within ScottishPower's transmission system
- The Scotland-England interconnector
- North Yorkshire
- Upgrade circuits through the Mersey ring

The range of costs provided cover the planting regimes (capacity mixes and different locations) considered in the 2010 scenarios.

The level of further investment required to upgrade capacity from 72% of the 2010 target to full compliance, is significant. Nevertheless, it is assumed that a new mechanism that adequately incentivises the TSOs will be in place by the time construction work needs to start as the capacity is required in the period 2006-2010. If this not the case, investment will remain an important bottleneck.

The total reinforcement costs of meeting the 2010 target are in the order of £1.4bn to £2.1bn.

Figure 3-1: Costs of 2010 Transmission Reinforcement



To meet the 2010 target further effort is needed to ensure urgent resolution of transmission related planning consent issues.

Additional new transmission circuits will be required to comply with the 2010 target. This will entail urgent resolution of planning issues. Assuming that planning is resolved to allow connection to the grid of generators planned for 2006, this issue becomes more possible. Otherwise, the 2010 further reinforcements will be difficult to achieve within the existing planning process and considering that Public perception of renewables will play a key role in planning-related issues for construction of new transmission system capacity.

Furthermore, any delays to the necessary investment, if not the actual work itself, could impact on project development rates, if developer/financier confidence in network investment and capacity is eroded. All the good intent which underpinned the policy decision to extend ROCs beyond 2010 will, similarly, be rendered less effective than hoped.

Achievement of 2020 Aspirational Target

Further reinforcements are needed in Scotland, to the Scottish-English Interconnector and in England to allow compliance with the 2020 aspirational target. These reinforcements are likely to costs in the order of £0.9bn to £1.1bn in addition to the 2010 costs.

Further reinforcements are needed in Scotland and in the Scottish -England interconnector to meet the 2020 target. Investment is primarily required in the following locations:

- Within SSE's transmission system
- The interconnection between the SSE and ScottishPower systems
- Within ScottishPower's transmission system
- The Scotland-England interconnector
- North Yorkshire

These reinforcements are likely to costs in the order of £0.9bn to £1.1bn in addition to the 2010 costs. The range of costs provided cover all of the planting regimes (capacity mixes and different locations) considered in the 2020 scenarios.

Our recommendation is that the Government and Ofgem carry out a further investigation into an HVDC offshore link between Scotland and England as a possible way of avoiding large levels of transmission reinforcement work and the associated planning issues. Studies by others have estimated the cost of a 2GW HVDC link along the west coast as being between £0.8bn and £1.7bn.

Given that the worst system capacity constraints occur during times of low (summer) demand, further investigation is recommended to identify possible cost savings through either changing the approach to system planning and security or by constraining off plant from time to time. Current network planning methods require the TSOs to use relatively high load factors for intermittent renewable generators such as wind farms in order to provide the required level of system security, although actual plant outputs may be much lower for some of the time.

A full cost-benefit analysis of the cost of constraining plant against the cost of network reinforcement should be carried out to clarify this issue. We also recommend that the effect of using seasonally adjusted load factors for intermittent renewable generation output is investigated when considering network reinforcement requirements, rather than current deterministic methods whereby a single fixed load factor is applied to generator output when planning reinforcement requirements.

It is also important that any further work investigates the effect of temporary network capacity reductions caused by the construction of new network components. In order to construct and commission new network sections it will be necessary to temporarily isolate existing sections of the networks for safety reasons, while work is undertaken.

Actions

2010

Action 4	Generators' business plans require connection to the grid for most projects by 2006. In order to ensure that generators' plans (72% of the 2010 target) are not delayed, the DTI/ Scottish Executive must facilitate planning consents for the necessary transmission reinforcements to start construction in 2004.
Action 5	To achieve full compliance with the 2010 target more generation capacity needs to come on line post 2006. This requires further transmission reinforcements. To ensure the 2010 target is met, the DTI/Scottish Executive must facilitate planning consents for the necessary transmission reinforcements post 2004.
Action 6	Achievement of generator's business plans and the 2010 target will be delayed if reinforcements are not put in place. To ensure that the transmission grid can connect the required capacity, the Transmission System Operators (TSOs) must confirm the necessary reinforcements, develop projects and be ready to start construction and upgrade transmission assets for connecting plants from 2006 onwards.
Action 7	Achievement of the 2010 target will be delayed if TSOs are not adequately incentivised to undertake the necessary investment. Ofgem and the TSOs need to finalise proposed means to incentivise TSOs to invest in the above assets.
Action 8	The DTI/Carbon Trust should commission ongoing studies into HVDC systems as an alternative to Transmission System reinforcements. Cost-benefit analyses are also recommended to find an acceptable balance between network reinforcement and constraining plant off the system.

Actions 4, 6 and 7 need to be acted upon now, Actions 5 and 8 need to be acted upon by 2004 -2005.

2020

Action 9	Achievement of the 2020 aspirational target means that the number of transmission-connected projects will increase. The TSOs need to identify the strategic investments required and set planning activities in motion by 2010.
Action 10	In order to ensure the 2020 aspirational target is met, Ofgem must provide an adequate incentive mechanism for the strategic investment required, and the DTI must facilitate planning consents for the necessary reinforcements and expansion work post 2010.

Actions 9 and 10 should be acted on by 2010, in order to allow long -term strategic decisions to be made ahead of actual system requirements becoming critical.

4 Network Development Needs: Distribution

Introduction

This section summarises the results of our analysis of the impact of increasing the level of renewables on the UK distribution networks to meet the 2010 target and the aspirational goal for 2 020[1]. It also analyses potential impacts of simultaneous expansion of the UK's CHP capacity. This section outlines the scale and cost of modifying, reinforcing and extending the system.

Other studies have been carried out on this subject, and these are referenced within Annex 3 of this report. However, the advantage of the current study over previous ones is that it is largely based on real projects and generators' business plans and uses a "bottom -up" approach to map rising renewable capacity onto the distribution networks. Also, differences may arise from this study's need (in common with other studies) to base results on a generic model to represent the UK distribution networks due to the lack of detailed information and impracticality of basing studies on full network information.

Methodology

Increasing amounts of distribution connected renewable generation (Step One to Step Three for all 2010 and 2020 scenarios) are modelled to assess bottlenecks and the need for reinforcement. The model is run with and without CHP projects assuming that 74% of the 2010 CHP target will be met. This assesses the impact of a simultaneous expansion in CHP.

The model is generic and constructed by:

- analysing the key statistics taken from the DNO Long Term Development Statemen ts.
- preparing a basis for "banding" renewable projects by installed MW capacity and predicting the probable connection voltage.
- examining the technical limitations of the existing distribution networks as a first stage in predicting the impact and costs o f reinforcement.

Key Findings

Achievement of Generator's Business Plans

Significant reinforcements are needed in Scotland at all voltages by 2006 to satisfy generators' business plans and to meet 72% of the 2010 target. These are likely to cost in the order of £385m. Less significant work is needed in the rest of the UK bringing the total in the order of £520m. This is a very significant level of investment and a potential bottleneck.

[1] Full details are included in Annex 3 of this study.

To meet the 2006 generators' business plans and thus reach 72% of the 2010 target, significant reinforcements at all voltage levels are necessary in Scotland. Costs are in the approximate order of £385m. Less significant work is also needed in the rest of the UK bringing the total in the order of £520m, noting that DNOs will have more accurate data on the basis of their studies, which may vary significantly from our estimate.

This level of investment is very significant and a bottleneck within the present regulatory framework for two main reasons:

- DNOs find difficulty in identifying reinforcement needs owing to uncertainty over project location caused by the lack of clarity on planning zoning.
- Whilst Ofgem and the DNOs are making progress towards devising a regulating regime for the connection of Distributed Generation (DG), continuing effort needs to be directed to ensure this gives the DNOs adequate incentives to connect new generators and to invest in the necessary strategic reinforcements.

The reinforcements needed in Scotland are likely to require the resolution of distribution related planning issues.

Much of the strategic reinforcement required in Scotland will be by 132 kV overhead lines. Our studies, which are based on generic models, do not identify precisely what is required to meet the generators' 2006 business plans. The study assumes the use of wooden pole 132kV circuits to ease the planning consent process but planning issues may still remain due to the scale of the reinforcement and new build needed. Currently, depending on the design of the lines (pylons or wooden poles), the terrain and the environmental sensitivity of the area, the period from conception to commission can be up to 5 years for wooden poles and up to 10 years for pylons, with most of that taken up by the planning consent process.

To ensure that construction is not unduly delayed, the Scottish DNOs need to identify the new circuits and initiate the planning consent process. Construction needs to start as soon as possible to make the new capacity available by 2006. Without this new capacity, the network rather than the actual business development plans will be the constraining element in the development of renewable generation capacity going forward.

Also, in order that the planning process is accelerated, it will be necessary for the Scottish Executive to use its powers to provide clear guidance to the planning authorities and for the DNOs to undertake a carefully managed and adequately consulted application process. Public perception of renewable power will play an important role in planning-related issues for both renewable power projects and the associated network reinforcement work, and the Scottish Executive in particular will have a key role to play in addressing public perception issues.

Full Compliance with the 2010 Target

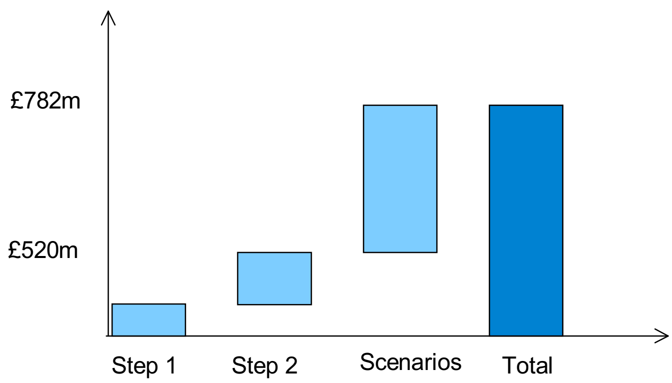
Further significant reinforcements are needed in Scotland and in the North West of England to allow 100% compliance with the 2010 target. Modest work is required in the rest of the UK with incremental costs in order of a further £201-265m.

To meet the 2010 target under both of the 2010 scenarios considered, there is a significant increase in the amount of new network build required in Scotland, with further costs in the order of £20 to £138m. Both 2010 scenarios show further reinforcement work required in the North West region with the High English Offshore Scenario presenting the worst case. In this instance, the work required is in the order of a further £108m. Relatively modest work is necessary in the rest of the UK, bringing the total in order of £201-265m[1].

The total reinforcement costs of meeting the 2010 target are in the order of £721 -782m. This is a considerable level of investment, compared to the combined annual capital expenditure of the DNOs, which is typically between £1bn and £1.4bn. This level of expenditure would need to cover all reinforcement costs, not just those due to renewable capacity. Nevertheless, it is assumed that a new mechanism that adequately incentivises the DNOs to undertake the required investment will be in place by the time construction work needs to start as the capacity is required in the period 2006 -2010.

The network costs are built-up as indicated Figure 4-1.

Figure 4-1: Cost of 2010 Distribution Reinforcement



CHP expansion to meet 74% of the 2010 target does not present a problem.

CHP expansion to meet 74% of the CHP 2010 target is not an issue. This is mainly because CHP plants tend to be in different locations to renewable generators – typically CHP is more likely to be found in urban areas whereas the bulk of renewables capacity is more likely to be found in rural areas.

[1] The ranges denote the variations in the different scenarios.

2020 Aspirational Target

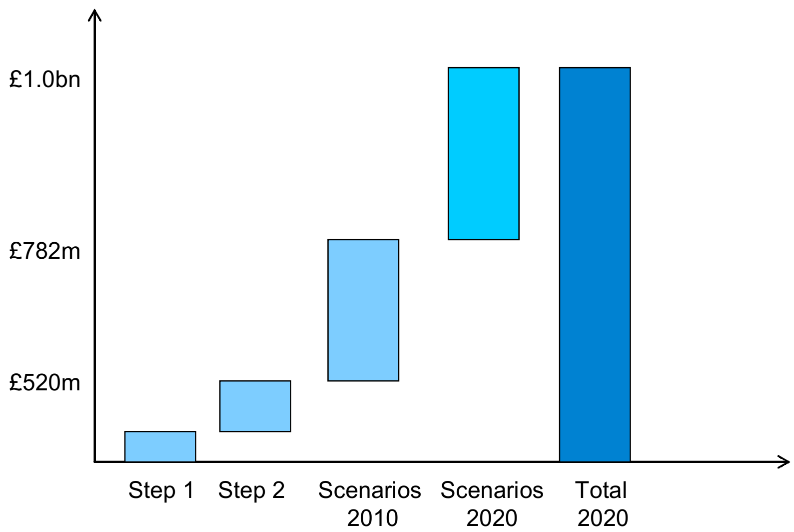
Further reinforcements are needed in Scotland and England. These are likely to cost in the order of a further £0.7bn to £1.0bn.

The results for 2020 show the following:

- Midlands and South of England require relatively modest levels of reinforcement of existing networks and new built for England-South only with estimated costs in the order of £33-177m. Reinforcements are likely to be at lower voltage levels and therefore will not present major planning issues.
- North of England and Wales need significant reinforcement of the existing capacity as well as new build with estimated costs in the order of £507-785m. This work is likely to entail new 132 kV lines with consequent potential planning bottlenecks. The relevant DNOs should identify the 132 kV requirements and initiate the planning consent process in 2010.
- Scotland needs relatively modest reinforcement due to the work undertaken to achieve the 2010 target with estimated costs in the order of £111-120m.

The range of costs provided covers the 2020 scenarios. The total reinforcement costs of meeting the 2020 aspirational target are in the order of £0.7-1bn and are built-up as indicated Figure 4-2.

Figure 4-2: Costs of 2020 Distribution Reinforcement



Actions

2010

Action 11	Generators' business plans have the greatest impact on the Scottish distribution networks with most projects requiring connection by 2006. In order to ensure that generators' plans (72% of the 2010 target) are not delayed, the Scottish Executive must facilitate planning consents for the necessary 132 kV reinforcements to start construction in 2004-2005.
Action 12	To achieve full compliance with the 2010 target more generation capacity needs to come on line post 2006. This requires further 132 kV reinforcements in Scotland and significant reinforcements in the North West of England. To ensure the 2010 target is met, the Scottish Executive and the DTI must facilitate planning consents for the necessary distribution reinforcements post 2004.
Action 13	Achievement of generator's business plans and the 2010 target will be delayed if reinforcements are not put in place. To ensure that the distribution networks can connect the required capacity, the Distribution Network Operators (DNOs) must identify the necessary 132 kV and lower level reinforcements, develop projects and be ready to start construction and upgrade assets for connecting plants from 2006 onwards.
Action 14	Achievement of the 2010 target will be delayed if the DNOs are not adequately incentivised to undertake the necessary investment. Ofgem and the DNOs need to finalise proposed means to incentivise TSOs to invest in the above assets as a matter of urgency.
Action 15	Achievement of the 2010 target will be delayed certainty over project location is not increased. DTI/Scottish Executive must ensure that planning authorities identify land use zoning for renewable energy.

Actions 11, 13, 14 and 15 need to be acted upon now, action 12 needs to be acted upon in 2004.

2020

Action 16	Achievement of the 2020 aspirational goal means that more generation capacity is connected to the distribution networks. In order to ensure that the networks are ready, DNOs need to identify the required strategic investments and set the planning procedures in motion by 2010.
Action 17	To ensure the 2020 aspirational target is met, Ofgem must ensure that an adequate incentive mechanism for investment is available and the DTI must facilitate planning consents for the necessary distribution reinforcements post 2010.

These actions need to be acted upon by 2010. This assumes that is sues have been dealt with for 2010; that DNOs have the right incentives in place to make the necessary investment and that the planning process has been accelerated.

5 Intermittency

Key Issues

Renewable energy sources such as solar, wind, wave, and tidal are intrinsically intermittent and are therefore unable to sustain a steady and consistent output. (The nature of the intermittency is, of course, different for the respective renewable energy technologies and this difference could be a relevant factor so far as mitigating the impacts of intermittency is concerned.) As the percentages of intermittent generation capacity increase and become more significant, additional uncertainty is created in the management of the electrical system on a real time basis to balance demand and generation. This requires increasing amounts of conventional reserve capacity that can be made available immediately (spinning reserve) and of plant capable of providing some of the ancillary services (frequency response) required to manage the system securely.[1]

Methodology

The key findings summarised in this report have been obtained from an exhaustive review of the relevant literature. The review has included literature developed in the UK by NGT, work to support the Performance Innovation Unit (PIU) in the Energy Review and studies carried out by several research institutes, amongst others.

We have also reviewed international American, German and Danish studies and in particular papers analysing the Nordel Grid and the Eltra power system.

Key Findings

Increasing levels of intermittent generation do not present major technical issues at expected

There are no major technical barriers to the implementation of dispersed intermittent generating systems connected to the networks and costs to 2010 will be small.

There are costs associated with intermittency: modest for 2010 but more significant for 2020, particularly due to the amount of reserve the system needs to carry.

As levels of intermittent generation increase, costs also rise and to 2020 they become more significant.

[1] Full details on the analysis of intermittency are included in Annex 4 of this report.

Our literature survey has identified (based on experience in US, Denmark, Germany and the UK) extra costs associated with intermittency. These are summarised as follows:

- Estimated extra operating balancing costs: £1.6-2.4/ MWh for 10% wind penetration and £1.9-2.8/MWh for 20% wind penetration, with the extra costs allocated to the intermittent generator. These costs depend on the costs of spinning reserve and providing operating frequency control, which are currently in the range of £3-6/MWh and £4.5/MWh respectively, based on present-day UK market prices, as contracted by NGT for ancillary services provision.

Based on these £/MWh costs, the estimated annual additional balancing costs due to intermittency as:

- £18m to £30m for 72% compliance with the 2010 RO target (equates to 5.3% wind penetration by system demand)
- £31m to £55m for full compliance with the 2010 RO target (equates to 7.6% wind penetration by system demand)
- £84m to £150m for full compliance with the 2020 aspirational target (equates to 14.2% wind penetration level by system demand)

In the context of economic appraisals of intermittent sources, compared to thermal plant, the value of the intermittent source may be specified as: [Fuel Saving] + [Capacity Saving Value] – [Costs associated with Intermittency]. The capacity value depends on the amount of displaced thermal plant (capacity credit). This is 3 300 MW for 10% wind and c.5 000 MW, or about 25% of intermittent dispatched generation, for 20% wind penetration.

The literature concurs significantly in its analysis of intermittency but further research is required in some areas.

The literature reviewed concurs significantly in its analysis of intermittency. In some occasions, the results are difficult to transplant to the UK because the systems are different or the base data is difficult to compare. There are a number of areas where further research may enable the costs associated with intermittency to be better understood, or reduced. The key areas include the following:

- balancing cost reduction, which in turn may come about through improved information on wind variability.
- improved wind forecasts
- institutional factors such as NETA do not necessarily enable proper allocation of the various components of costs and values for intermittent sources
- examination of the level (and cost) of reserve, particularly as wind penetration increases
- other options for reserve such as storage and demand side management.

Actions

Action 18	To ensure that intermittency costs are fully understood, and to identify potential cost reduction strategies, the Carbon Trust and the DTI should commission further research in this area.

This action should be acted upon now, with the view of having the results of the analysis in the early part of 2004.

6 Grid Code Compatibility

Key Issues

Grid compatibility is related to the technology and the level of penetration into the electricity system of that technology. [1]In the case of renewables, grid compatibility is most relevant to wind turbines and less important for other types of renewables. From the point of view of the electricity grid, biomass and CHP plants behave like conventional thermal plants. The impact of PV and other technologies such as wave and tidal is much less due to their low penetration levels at present and in the period to 2010. In turn, there are increasing numbers of wind farms, larger in size, applying for connection to the grid system.

One of the major grid code compliance problems for traditional wind turbine technology used in large wind farms is that it does not provide an appropriate response under fault conditions, creating a risk of local as well as more widespread power failures. This issue could also apply to other future technologies (wave and tidal) when their penetration levels increase in the future. There are also several other grid code compliance issues affecting wind farm operations, and these are discussed below.

The grid operators are responding to this by modifying grid codes. These codes contain connection rules and represent a specification that allows adequate integration of generation into the transmission network and safe operation of the system. The Grid Code is binding for all generators connected to the grid.

Wind turbine manufacturers are also reacting to the grid code compliance issue by developing their existing designs further.

Methodology

The issue of grid code compliance has been analysed by a combination of UK and international literature review, industry knowledge and discussions with TSOs, wind manufacturers and wind developers. The following entities have been contacted:

- The UK's three transmission operators
- Major wind turbine manufacturers
- Several major wind farm developers

Key Findings

Technology

Current designs are, largely, not compliant with present or proposed grid codes, which raises compliance issues for new-build projects.

Current wind turbine designs are not compliant with the present grid codes in Great Bri tain (GB) in the following areas:

- the ability to remain connected during a grid system fault (referred to as 'fault ride through')
- reactive power capability
- frequency operating range, particularly at higher levels, between 51 Hz and 52 Hz.

While operational wind farms have obtained connection agreements on a case by case basis, future projects will come under increasing pressure to comply fully with the proposed grid codes.

Manufacturers currently do not guarantee grid code compliance for their products. However, they claim that the technology exists to achieve full compliance during 2004.

The technology exists to attain full grid code compliance and manufacturers cla im that this could be achieved during 2004. Nevertheless, and based on experience of manufacturers' previous claims, compliance may be delayed as the decision has costs and time implications.

Turbines that use electronic converters on all their output are becoming increasingly well-established in the wind turbine market, making grid code compliance less problematic.

Manufacturers do not accept grid compliance liability; this inhibits project finance and it questions the manufacturers' statements about technology availability. The lack of such guarantees could have a serious affect on the development of future projects, which in turn affects achievement of the 2010 RO target. .

Commitment to meet the grid code requirements is established between the project developer/operator and the grid operator. Wind turbine ma nufacturers are one step removed from this p rocess. At the moment, manufacturers are not accepting liability for grid code compliance and this is a serious issue for smaller developers trying to raise finance. This reluctance impacts on manufacturers' cla ims that full compliance will be possible at some point before the end of 2004.

Manufacturers would have more time available in which to gain sufficient field experience with new designs to provide compliance guarantees if some of the proposed grid code requirements were delayed.

If temporary relaxation to FRT requirements is not provided by the TSOs, it could potentially create a bottleneck to achievement of the 2010 target. However, the manufacturers must use the additional time that relaxation of FRT requirements would provide to gain sufficient operational experience with new designs to allow grid code compliance guarantees. Without such guarantees the manufacturers' claims to be grid code compliance are insufficient to tackle project finance issue s.

Grid Codes

Grid Codes are system specific. Wind turbine manufacturers believe that the most onerous grid codes are those in GB.

Although all grid codes share some similarities they are system specific and depend on the generation mix and level of interconnection of a particular system. This means that manufacturers who operate in global markets usually design their turbines for the most onerous conditions to avoid the extra costs of modifying designs for particular systems. Presently, wind turbine manufacturers believe that the most onerous grid codes are those in GB regarding fault ride through and frequency operating range.

At present GB has two different grid codes; one is applicable for generation connected to the transmission network in England and Wales and the other is for Scotland. Currently, there is a consultation process in place to modify the existing two GB grid codes, which will ultimately result in two virtually identical ones. There is also the intention of having one single grid code for the whole of GB, post-BETTA.

The proposed GB Grid Codes are not significantly "gold plated" when the obligations placed upon the TSOs are considered, but relaxation of the Fault Ride Through requirements, power factor range and the frequency control requirements may be desirable in the interim, although this should be for a fixed period to be determined by the stakeholders.

A review of the proposed changes to both grid codes indicates that the new grid codes will be reasonable in scope and will not be significantly 'gold-plated', considering the requirements placed on the TSOs by the specific configuration of the GB system compared to other grid systems.

There would not appear to be any difficulties in implementing the Voltage Control requirements of the proposed grid codes. Manufacturers appear to be able to provide adequate frequency control by the end of 2004, noting the qualification that it will be facilitated via central control of turbines rather on individual machines. This qualification should not affect the issue of compliance. With regard to tolerance of frequency variations on the system, the evidence indicates that manufacturers can comply with the proposed grid code requirements.

Nevertheless, there are number of areas where absolute values may be relaxed and the date set for compliance extended beyond 2004, which is the expected date for the introduction of the new grid codes (see Table 6-1). These include the following:

- Relax the date for introduction of fault ride through (FRT) requirements until wind turbine manufacturers believe that their turbines will be compliant. This could have some cost implications as it would be necessary to provide additional generation reserve to cover for the lack of FRT capability in new wind farm developments.
- Due to the high cost implications for reactive power control the power factor range could be relaxed until more wind penetration is achieved. Power factor control within 0.95 lag to 0.95 lead should be acceptable in the meanwhile.

- Provision of frequency control could be removed until wind penetration levels increase, although the TSOs need to provide clarity on what the critical wind penetration level is with respect to frequency control issues. Presently there is adequate conventional generation providing enough frequency control, although manufacturers are claiming (but not guaranteeing) compliance by the end of 2004.
- Alternatively, mandatory frequency control could be replaced with a market-based response for frequency control. This is an approach favoured by developers, as a properly developed market would allow the TSOs to maintain satisfactory frequency control, while reducing the compliance issues for wind farms.
- The TSOs have indicated that these requirements could be delayed until around 2005, although the corresponding level of wind penetration they have assumed by this date was not provided.
- We recommend that the level of wind penetration at which FRT and frequency control become critical are explored in detail, with a view to providing confidence in system operation if some grid code requirements are delayed.

At present, applications for connection are dealt with on a case by case basis, and a significant delay in the introduction of the amended grid code requirements would mean that this approach continues for the expected new onshore and offshore wind farm developments. This is unacceptable both to wind power developers and to the TSOs, as continuing this approach in the long term could compromise system security.

Table 6-1: Table of Responsibilities

Compliance Issue	Action Required	Responsible Party
Power Factor	Technical Improvements	Manufacturers
Power Factor	Relax lagging pf requirement to 0.9	TSOs
Frequency Control	Technical Improvements	Manufacturers
Frequency Control	Investigate the feasibility of a frequency control market	Ofgem/TSOs
Fault Ride Through requirements	Identify critical wind power penetration level, with a view to possible relaxation of requirements	TSOs
	Install disturbance monitoring equipment.	TSOs
	Relax fault ride-through requirement for of 15% voltage, for the interim.	TSOs
	Use the additional time provided by grid code relaxations to gain sufficient field experience to provide compliance guarantees.	Manufacturers
Test FRT Capability	Develop methodology and systems/equipment to allow full testing of generator design compliance.	ALL.

Actions

Action 19	Testing fault ride-through is still unresolved and it needs further discussion amongst TSOs, manufacturers and developers, leading to agreement by TSOs that particular designs are generically compliant. A fault-ride through capability down to 15% voltage is required as soon as possible, but we do not believe the case for FRT down to 0% voltage has been fully proven.
Action 20	The new proposed grid codes for GB are based on a level of wind penetration that is not likely to be realised until 2005-2006 assuming that planning issues for both generation and transmission are resolved. To avoid further delays in capacity expansion, TSOs could grant extensions to some of the grid compliance issues until wind penetration levels reach a level critical to the TSOs.

Action 19 needs to be acted upon now and Action 20 in 2004.

7 Other Issues

There are a number of additional issues which directly or indirectly affect provision of sufficient renewable generation to meet the 2010 target and/or the associated level of network. These are discussed briefly below.

- To allow the TSOs to plan effectively for impacts caused by high levels of DNO -connected projects there must be a clear and full transfer of information from the DNOs to the three TSOs on planned and projected network connections. In general, infor mation sharing between all relevant parties is a key issue.

- Current and ongoing work by such groups as the Technical Steering Group of the Distributed Generation Coordination Group (TSG) play a key role in developing better understanding of the issues, including those raised by this study for the DTI's Renewables Advisory Board. Continuation of support and resources for such groups is therefore an important part of the overall process of removing barriers to achieving the 2010 (and 2020) target.

- The current distribution price control review presents an important opportunity to address many network issues and incentive-related issues which could impact positively on the provision of network improvements. Given the importance which the Government attaches to setting and meeting its demanding renewable energy targets, and given the need for the urgent action identified in this study, this particular review i s even more crucial.

- All TSOs and DNOs have, to varying degrees, analysed the impact of different levels of renewable and embedded generation on their networks. This work provides a platform for moving forward in a cohesive way towards the common goal of enabling achievement of the RO target.

- Public perception of renewable power will play an important role in planning-related issues for both renewable power proje cts and the associated network reinforcement work.