ASSESSING THE IMPACT OF AMENDMENT PROPOSAL 148

August 2008

A report for the British Wind Energy Association

Submitted by:

Cambridge Economic Policy Associates Ltd

CAMBRIDGE ECONOMIC POLICY ASSOCIATES
EXECUTIVE SUMMARY

Widespread dissatisfaction with the arrangements for gaining a connection to the transmission system have led to a series of proposals to reform transmission access arrangements being brought forward. CAP148: “Deemed Access Rights to the Transmission System for Renewable Generators” proposes to grant eligible renewable generators access in a fixed time period, irrespective of whether works to upgrade the transmission system have been completed.

This report finds that the Deemed Transmission Entry Capacity product introduced by CAP148 would be expected to prove attractive to primarily onshore wind generators and would tend to enable wind generators to connect at a slightly early date than would otherwise have been the case. However it considers that, when the various factors which inhibit project development and the risks of the product are considered, the volume of generation using the product would be significantly lower than the total capacity detailed in National Grid’s capacity register. The volumes of generation expected to benefit from CAP148 are shown in the table below.

Incremental capacity brought forward by CAP148 (MW)

<table>
<thead>
<tr>
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</tr>
</thead>
<tbody>
<tr>
<td>3 year lead time</td>
<td>768</td>
<td>627</td>
<td>374</td>
<td>799</td>
<td>756</td>
<td>661</td>
<td>0</td>
</tr>
<tr>
<td>4 year lead time</td>
<td>0</td>
<td>772</td>
<td>487</td>
<td>799</td>
<td>756</td>
<td>661</td>
<td>0</td>
</tr>
</tbody>
</table>

The report finds that the increase in connected generation will cause a short term increase in the costs of operating the system; by increasing the frequency of network constraints and creating a need for the system operator to hold additional reserve.

The report also finds that the proposal will have a series of both qualitative and quantitative benefits. The greater scope and flexibility provided to network companies in undertaking investment may be expected to promote innovation, particularly if appropriately incentivised, and could deliver long-term cost savings. In addition the proposal would go some way towards facilitating the achievement of European Commission and Government renewables targets.

We find that the displacement of conventional generation by increased volumes of renewable generation would be expected to increase wholesale market competition and put downward pressure on wholesale prices, as well as delivering substantial carbon savings. Our central case estimate of the costs and benefits of CAP148 are shown in the table below.
### Annual costs and benefits of CAP148 (£m) – 4 year lead time

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Reserve/ Ancillary Service Costs</td>
<td>&lt;3.09&gt;</td>
<td>&lt;1.95&gt;</td>
<td>&lt;3.20&gt;</td>
<td>&lt;3.02&gt;</td>
<td>&lt;2.64&gt;</td>
<td>0</td>
</tr>
<tr>
<td>Constraint Costs</td>
<td>&lt;54.11&gt;</td>
<td>&lt;10.28&gt;</td>
<td>&lt;58.41&gt;</td>
<td>&lt;56.26&gt;</td>
<td>&lt;49.93&gt;</td>
<td>0</td>
</tr>
<tr>
<td>Cost</td>
<td>&lt;57.20&gt;</td>
<td>&lt;12.23&gt;</td>
<td>&lt;61.60&gt;</td>
<td>&lt;59.29&gt;</td>
<td>&lt;52.58&gt;</td>
<td>0</td>
</tr>
<tr>
<td>Decrease in wholesale prices</td>
<td>2.37</td>
<td>1.49</td>
<td>2.45</td>
<td>2.32</td>
<td>2.03</td>
<td>0</td>
</tr>
<tr>
<td>Carbon Savings</td>
<td>43.15</td>
<td>27.74</td>
<td>46.47</td>
<td>44.85</td>
<td>39.99</td>
<td>0</td>
</tr>
<tr>
<td>Benefit</td>
<td>45.51</td>
<td>29.24</td>
<td>48.92</td>
<td>47.16</td>
<td>42.02</td>
<td>0</td>
</tr>
<tr>
<td>Net Cost/ Benefit</td>
<td>&lt;11.69&gt;</td>
<td>17.01</td>
<td>&lt;12.68&gt;</td>
<td>&lt;12.12&gt;</td>
<td>&lt;10.56&gt;</td>
<td>0</td>
</tr>
</tbody>
</table>

The impact of CAP148 is dependent on a series of variables and forecasting the impact with any degree of accuracy is difficult. On balance the report concludes that it is likely that the variant of the proposal with a four year lead would be expected to have a net present cost of circa £23 million. However, it also finds that it would be expected to deliver a series of additional qualitative benefits and that, under a range of credible scenarios, outcomes could vary between a more significant net cost and a net benefit.
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1. **INTRODUCTION & OVERVIEW**

1.1. **Terms of reference**


The BWEA has commissioned the assessment to inform the debate about transmission access and the connection of renewable generation by providing greater clarity to the potential costs and benefits of the proposal.

1.2. **Cambridge Economic Policy Associates**

CEPA is a London-based economic and financial policy advisory firm specialising in regulation and competition. We provide policy advice on efficient regulation, the creation of incentives and on the appropriate role of markets and private capital, alone or in partnership with the public sector, in the delivery of public services across the UK and Europe.

Our work for governments and economic regulators has seen our experienced staff apply best practice to design, develop and implement regulatory frameworks and create incentives to enable or enhance effective competition, while our advice to regulated companies has allowed them to understand and influence regulatory regimes. We are specialists in the financial aspects of regulation, viewed as a leading authority on the appropriate cost of capital and financeability issues and experienced financial modellers.

1.3. **Approach**

In undertaking the assessment, CEPA has sought to quantify impacts to the extent practicable, drawing on publicly available data from a range of sources\(^1\). CEPA’s analysis has been informed by Professor David Newbery, our vice chairman. David is the Research Director of the Electricity Policy Research Group at Cambridge University and an internationally recognised expert in regulatory economics and, particularly, transmission access issues.

The assessment has also been informed by discussions with a representative range of stakeholders, including vertically integrated generation and supply businesses, independent renewable power producers, National Grid and Scottish transmission licensees and Ofgem.

Due to the difficulties in forecasting how the market will develop with any degree of accuracy, we have developed a financial model to accompany the document. The document

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\(^1\) CEPA’s terms of reference do not include detailed modelling of impacts on energy prices or constraint costs and volumes.
is structured around the model, allowing users to input their own views about each of the key variables. For each of these variables we discuss key issues, possible options and the rationale for our assumptions.

1.4. Issues outside scope of the proposal

This assessment does not seek to duplicate the impact assessment which the Office of Gas and Electricity markets (Ofgem) has carried out under Section 5a of the Utilities Act². Ofgem is required to consider the proposal against its primary and wider statutory duties and to consider any issues of compliance with domestic and European legislation that would arise from its implementation. This assessment considers the likely costs and benefits of the proposal on the energy market and transmission network. It does not seek to consider any issues relating to aspects of British or European law. However, in developing the document we have, as far as possible, had regard to Ofgem’s guidance on impact assessments³.

1.5. Structure of the document

As mentioned above, the document is accompanied by a model and structured in accordance with it. The remaining sections are as follows:

- Section 2 provides background and context to CAP148.
- Section 3 provides an overview of our approach and methodology.
- Section 4 discusses the approach we’ve taken to building up a forecast of the volume of generation that might be expected to make use of CAP148 and determining the period for which the impact might be felt.
- Section 5 assesses the impact on the costs of system operation and network investment.
- Section 6 considers the possible benefits of the proposal, including the impact on wholesale prices and carbon savings.
- Section 7 discusses qualitative costs and benefits.
- Section 8 presents our results.
- The document has a series of appendices.
  - Appendix 1: Provides additional background and context to the issues that have prompted CAP148 to be raised.

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² See http://www.ofgem.gov.uk/CustomPages/Pages/Results.aspx?k=CAP148
³ http://www.ofgem.gov.uk/About%20us/BetterReg/IA/Documents1/GUIDANCE%20ON%20IMPACT%20ASSESSMENTS.pdf
Appendix 2 considers the need for network investment.

Appendix 3 discusses the factors which act as barriers to developing renewable generation projects in more detail.

Appendix 4 provides results under a series of alternative scenarios and presents sensitivities to show the impact of changing key assumptions.

Appendix 5 discusses estimates of the cost of carbon and considers difficulties in estimating the value.
2. **BACKGROUND & CONTEXT**

2.1. **Overview**

This section provides an overview of Connection and Use of System Code (CUSC) Amendment Proposal (CAP) 148 and the various combinations and permutations developed by the Working Group appointed by the CUSC Panel to assess the proposal. Further information on the factors which caused the proposal to be raised, most notably the significant lead times for securing a connection to the transmission network, are contained in Appendix 1.

2.2. **CAP148**

CAP148 is one of a number of recent proposals to amend the rules for allocating transmission capacity. It has been raised in response to the persistent delays being experienced by potential connectees in securing access to the wholesale market. CAP148 was raised by Wind Energy (Forse) to change the market rules to address a number of the key deficiencies it perceives with the existing regulatory framework. In its original form it sought to:

- Provide renewable generators with guaranteed network access (via a product called Deemed Transmission Entry Capacity (DTEC)), subject to a local connection being complete (i.e. the generator being capable of exporting power to the transmission network), at the later of 3 years (determined as the period in which an average reinforcement could be completed) after:
  - The point at which the project receives planning consent.
  - The date the Bilateral Connection Agreement (BCA) is signed.
- Guarantee that non-renewable generation would be constrained off before renewable generation and to provide an administered pricing schedule for conventional generation.
- Use increased revenues from transmission charges to offset any increase in operational costs.

The proposal was assessed by a Working Group which made substantial revisions to it. In particular, the elements of the proposal relating to changes to the rules for system operation were removed (i.e. generation would continue to be constrained on the basis of cost as reflected by bids and offers in the Balancing Mechanism) and the proposals to ring-fence charges were considered out of the scope of a CUSC amendment.

The Working Group developed a series of variants for CAP148, based on 3 differentiating factors.
• **Eligibility** – the subset of plant able to take advantage of the CAP148 arrangements and purchase DTEC.

• **Risk Allocation for delays in Wider Works** – the extent to which there should be relief for National Grid based on delays to wider transmission works.

• **Lead Time** - The earliest time the eligible generator can receive access to the transmission system, subject to completion of the Directly Consequential Works and the commissioning of the generator.

It therefore developed a variety of combinations and permutations based on the amalgamation of an approach to eligibility, an approach to risk allocation and a choice of two lead times. The possible combination and permutations are shown in the table below sourced from the report developed by the CAP148 working group.

*Table 1:1: Matrix of alternative options*

<table>
<thead>
<tr>
<th>Eligibility</th>
<th>1) All REGOs</th>
<th>2) Intermittent REGOs only</th>
<th>3) Low Carbon Generation 4</th>
<th>4) All REGOs minus proportionally qualifying plant</th>
</tr>
</thead>
<tbody>
<tr>
<td>Risk Allocation</td>
<td>A – As now</td>
<td>B – No relief for planning</td>
<td>C – No relief</td>
<td></td>
</tr>
<tr>
<td>Lead Time</td>
<td>X – 48 Months</td>
<td>Y – 36 Months</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Source: National Grid CAP148 working group report*

Multiple options were therefore created based on one of four eligibility definitions, three approaches to providing relief from planning delays and two potential lead times. The Working Group was asked to vote on the various options against the applicable CUSC objectives and to indicate their preferred option. A majority of participants indicated that combination 4BX (i.e. eligibility for all REGO’s minus proportionally qualifying plant, no relief for planning delays and a 48 month lead time) was preferable.

This assessment does not consider each of the individual variants in turn. As a base-case, we assess the impact of the Working Group’s preferred option. We also note that the model which we have developed to accompany this document should allow parties to assess the impact of alternative options should they so wish.

### 2.3. Charging

The nature of industry governance arrangements is such that changes to the CUSC and charging methodologies (which detail how charges for connection to and use of the system are calculated) cannot be discussed in the same arena. Therefore, were CAP148 to be approved, National Grid would be obliged to bring forward a change to the use of system

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4 Where low carbon involves the production of less than 0.2 tonnes of carbon per MWh.
charging methodology (consistent with the objectives of its charging methodology) to introduce a charge for the DTEC product\(^5\). National Grid issued an open letter on 2 October 2007\(^6\) setting out its view on charging issues.

National Grid noted that the proposal would be expected to cause an increase in operational costs and was of the view that any price should not be related to the cost of providing assets. It stated: “National Grid considers that access provided through DTEC, early connection, should be seen as an additional service and priced appropriately i.e. at the marginal operational cost associated with providing it, as far as it is reasonably practicable.”

It noted that prices could be calculated on an ex-post or ex-ante basis and further noted the need to develop a clear and transparent method of apportioning costs, given that single actions can have multiple impacts.

We do not consider that it would be practicable to undertake a complete assessment of CAP148 without considering the mechanism through which it will be charged. This is particularly the case as our discussions with stakeholders seemed to suggest that their views on the relative costs or benefits of the proposal are driven by an assumption about the charging regime that will be implemented, rather than necessarily the merits of the CUSC amendment proposal.

The charging arrangements will be an important determinant of the risk associated with using DTEC and as such the number of projects that choose to use it. It will also influence the extent to which increased constraint costs are perceived as a problem. For example, were overrun charging arrangements of the type envisaged by National Grid implemented, and were those charges calculated accurately, new generation would connect to the network until the point that it was no longer profitable for it to do so. As the charge would be fully reflective of the incremental costs caused by that party, system users would see no increase in transmission costs. As long as the overrun charge was not so great that no generator sought to take advantage of the arrangements, CAP148 would be expected to have beneficial impacts.

The assessment is therefore based on a scenario in which the existing TNUoS charging arrangements were applied to DTEC generators. In this case there would expect to be incremental costs which would need to be offset against any benefits likely to result from the proposal.

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\(^5\) This is because one of the relevant charging methodology objectives is reflecting developments in the transmission business.

3. **APPROACH AND METHODOLOGY**

3.1. **Overview**

This section briefly sets out the approach and methodology which we have adopted in assessing the impacts of CAP148. It also discusses the interaction between this document and the accompanying model.

3.2. **Approach**

In developing this document we have first considered the volume of generation likely to use DTEC, before considering the impact of this volume on the costs of network investment and operation, the impact on the wholesale market and any carbon savings.

Within each of these areas we discuss the key drivers of results and the assumption we have used in reaching our central estimate. We note that both the availability of data and the scope of the project mean that, to a significant extent, the assessment draws on data that is already in the public domain and does not seek to duplicate or verify any analysis that has been carried out by the CAP148 Working Group or other parties.

Our assessment has also been informed by discussions with a representatives range of stakeholders, including vertically integrated generation and supply businesses, independent renewable power producers, National Grid and Scottish transmission licensees and Ofgem. We would like to thank all the parties that took time to discuss their views.

Given the uncertainties over the impact of the proposal and the inevitable differences in views between interested parties we have developed a model to support the document which allows parties to input their own views on each of the key determinants of results.

3.3. **Methodology**

At the highest-level there are two key issues to establish in assessing the proposal:

- The volume of generation that might be expected to seek to connect to the network ahead of the point at which it is GB SQSS compliant (i.e. necessary upgrades are completed) and its impact on the costs of network operation.

- The impact that volume of generation will have on wholesale market behaviour and any associated benefits in lower energy prices or carbon savings.

Within each of these two broad categories there are a series of more detailed questions to address.
In establishing generation volumes it is necessary to consider:

- The volume of generation that is currently seeking to connect to the network, factors which might prevent a proportion of this generation from connecting and the way in which CAP148 might increase certainty and cause more applications for connection.

- The earliest time at which projects that are currently in scoping, planning or consenting could be completed, relative to the time at which wider transmission reinforcements are expected to be completed and therefore the period for which the incremental impacts of CAP148 would be expected to be felt.

- Based on the volume of generation expected to take advantage of CAP148 and the period for which the system will remain non-compliant with security standards, the likely impact on the frequency of constraints and costs of resolving those constraints.

In considering energy market impacts it is necessary to consider:

- The extent to which the volume of generation connected more quickly because of CAP148 will impact on wholesale market behaviour, competition and prices.

- The impact of that generation in terms of tonnes of carbon and the price at which any carbon saving should be valued.

These second two areas should identify the potential benefits associated with the proposal. The costs and benefits can then be compared using an appropriate discount rate. We also discuss a series of additional qualitative costs and benefits in section 7 of the document.

3.4. Using the model

At the highest level, the model considers the total volume of generation (as set out in National Grid’s TEC register as of June 2008) which could, in theory, take advantage of the CAP148 arrangements if implemented and scales this volume to reflect the various factors which will cause a proportion of planned capacity not to connect. Where capacity does not connect it is assumed that it re-enters the planning process.

The model uses a series of average project development timescales for different sized projects, chosen following discussions with developers, to determine the time at which projects that are currently at varying stages of the development process would be able to become operational.

Comparing this date to the current forecast completion dates within the TEC register allows the period for which the impact of CAP148 would be felt to be established. Assumptions

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7 The TEC register details all parties that have applied for Transmission Entry Capacity and received a connection offer. It is available from http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/tectrading/
about load factors, the incidence of constraints (which will reflect available headroom on the system) and the price at which constraints would need to be resolved allows an incremental operational costs to be calculated.

Benefits are calculated using assumptions about the extent to which renewable generation displaces conventional generation, changes in market prices and corresponding carbon savings. These issues are then drawn together to provide an overall net cost/benefit associated with the proposal.
4. **VOLUME OF ELIGIBLE GENERATION**

4.1. **Overview**

Understanding the likely volume of generation that may be expected to take advantage of the CAP148 arrangements is the first step in assessing the impacts on transmission costs and the wholesale market. Having developed an estimate of this volume, it is then necessary to consider the period for which the impact will be felt (i.e. the period between the point plant connects and the point when the reinforcements are completed and the network returned to GB SQSS compliance).

4.2. **Approach**

We have used various measures to come up with a estimate for the volume of generation that might seek to use DTEC. These factors are:

- The volume of generation that has asked for connection to the GB transmission network and the current status of those projects.
- The risks involved in purchasing the DTEC product and the most frequent barriers to project development to determine a probability of attrition (at each stage of the development process) which can be applied to this volume.
- Other factors which might indicate project’s willingness to use DTEC, including the way it might be expected to change behaviour and lead to dynamic effects.

We have sought to translate this volume of generation into an expected profile using a series of average project development timescales for plants of varying sizes. This allows the earliest time at which projects at various stages of the development process would be in a position to complete development and begin generating - were a connection in place.

Where this connection date is earlier than the contracted connection date contained in the TEC register (which should be reflective of the transmission companies’ best estimates of when transmission reinforcements will be completed), we have measured the difference – which reflects the period for which the impact of CAP148 would be felt and developed an expected profile of connected generation. Where the contracted connection date is earlier than the feasible connection date, it is assumed that the generator would have no incentive to apply for DTEC.

The supporting model allows the user to vary any of the elements of the average project development timescales and the size thresholds, allowing scenarios involving increased delays or the resolution of current issues to be considered. It also allows the user to specify an additional delay to all transmission reinforcements, which extends the period for which the impacts of CAP148 are felt.
4.3. The generation volume

We have used data contained in National Grid’s publically available TEC register as our base case data set. We have sorted this data to exclude any non-eligible projects or projects which have already connected. We have also excluded offshore wind generation. Our assumption is that offshore wind generation would be unlikely to use DTEC for a number of reasons:

- The regulatory framework to be applied to offshore wind generation is not clearly defined.
- Assuming the local connection work covers the connection to shore, we consider that this may be likely to be the critical driver of the timescale for connection.
- The proposed offshore regime appears to include incentives and compensation mechanisms for timely delivery (delivering many of the benefits of CAP148).
- The risk of using the product for a project of the scale of an offshore windfarm may be more material than an onshore equivalent.

This has allowed us to develop a data set of qualifying generators which could, in principle, take advantage of the CAP148 arrangements. A breakdown of this generation volume by TO area is shown below.

Table 4.1: Breakdown of eligible volume by transmission licensee

<table>
<thead>
<tr>
<th>Transmission Licensee</th>
<th>Volume (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NGET</td>
<td>299.00</td>
</tr>
<tr>
<td>SPTL</td>
<td>2,886.70</td>
</tr>
<tr>
<td>SHETL</td>
<td>4,206.60</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>7,392.30</strong></td>
</tr>
</tbody>
</table>

Source: National Grid TEC Register June 2008

The breakdown of projects by stage of development is shown in Table 4.2 below.

Table 4.2: Volume of generation by project status

<table>
<thead>
<tr>
<th>Project Status</th>
<th>Volume (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scoping</td>
<td>1,628.00</td>
</tr>
<tr>
<td>Under Consideration</td>
<td>2,910.15</td>
</tr>
<tr>
<td>Application Approved</td>
<td>1,018.55</td>
</tr>
<tr>
<td>Application Refused</td>
<td>309.80</td>
</tr>
<tr>
<td>Under Construction</td>
<td>127.30</td>
</tr>
<tr>
<td>No Information</td>
<td>1,398.50</td>
</tr>
</tbody>
</table>
### 4.4. Average project development timescales

We have consulted various stakeholders to consider the average development timescales for wind generation projects. Understanding this timescale informs the assessment of the volume of generation that may be in a position to make use of the CAP148 arrangements. We have considered the extent to which the development timescales can be expected to differ as a result of project size and have developed a series of timescales based on project sizes. While each project will be unique and would be expected to experience different issues, we consider that the timescales are broadly representative. We also note that our model allows the user to specify their own best estimates of project development timescales to be varied.

**Table 4.3: Average Project Development Timescales**

<table>
<thead>
<tr>
<th>Project Phase</th>
<th>Less than 50MW</th>
<th>50-100MW</th>
<th>100-250MW</th>
<th>250MW +</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scoping phase</td>
<td>3</td>
<td>3</td>
<td>6</td>
<td>6</td>
</tr>
<tr>
<td>(months)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Environmental Studies</td>
<td>12</td>
<td>15</td>
<td>18</td>
<td>21</td>
</tr>
<tr>
<td>(months)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Planning</td>
<td>14¹</td>
<td>24</td>
<td>24</td>
<td>27</td>
</tr>
<tr>
<td>(months)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pre-Construction</td>
<td>15</td>
<td>15</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>(months)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construction</td>
<td>9</td>
<td>9</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>(months)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energisation</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>(months)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total months</strong></td>
<td><strong>56</strong></td>
<td><strong>69</strong></td>
<td><strong>81</strong></td>
<td><strong>87</strong></td>
</tr>
</tbody>
</table>

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¹ Our assumption is that any project where no information is available is at the start of the scoping stage.

² For projects of less than 50MW the average planning timescale is quoted as 14 months in issue 12 of the BWEA’s Real Power publication.
4.5. The probability of attrition

There are a series of factors which are likely to reduce the volume of generation that will connect to the network. We have considered these factors and applied a probability of attrition to both our base case and CAP148 scenarios.

- A proportion of capacity will fall away during the planning process, as the approval process frequently requires a reduction in capacity.

- There are a series of factors, discussed in more detail in Appendix 3, many of which interact with each other to create more severe barriers to development, that will cause delays or terminations to projects, including:
  - Failing to secure planning permission – we note that the average planning success rates in 2007 were 56% in Scotland and 62% in England.
  - Objections by the Ministry of Defence or NATS en-route Ltd because of the impact of wind generation on radar – while objections only relate to circa 5% of projects (26 sites in total) they typically arise with large projects, both on- and offshore meaning the volume of MW affected is considerably higher.
  - A failure to secure finance or other project risks.
  - Delays or cancellations associated with a difficulty (including the escalating cost) of procuring and installing turbines.
  - Outside of the planning process a proportion of projects will also fail in the development phase.

There are also a series of reasons to suggest that DTEC may not be a product which is attractive to all generators. These issues are also discussed in more detail in Appendix 3.

4.5.1. Dynamic Issues

As well as generation which has currently applied for connection, it is possible that the availability of DTEC could bring forward more requests for connection. This impact is difficult to forecast with any degree of certainty.

The strong incentives to apply for capacity at as an early a stage as possible as a result of the British Electricity Transmission & Trading Arrangements transitional arrangements (which provided a guaranteed right to use the transmission network if parties applied before a certain date) and current queue for capacity, may have created applications to apply speculatively for capacity, meaning little additional generation may come forward in response to CAP148. Alternatively the 2020 connection dates available in Northern Scotland under existing arrangements may have reduced incentives to apply for a connection and mean a considerable volume of either wind or other technologies may come forward.
We have not sought to forecast the dynamic impact of the proposal. However we assume that an equivalent amount of capacity to that which falls away because of failure to gain planning consents or the wider issues discussed above reappears for capacity.

4.6. Central Case

We have considered the various factors which may prevent or discourage parties from using CAP148 to produce:

- **The volume of generation that would, in theory, consider using CAP148.** Our assumption is that all eligible onshore generation would consider using CAP148. However, we do not consider that it would be an attractive proposition for offshore developers.

- **A probability that projects are terminated.** We recognise that there are a range of factors that could increase the probability of attrition. However, we consider that using a 50% success rate, representing the status of the planning process as the single greatest barrier to development while reflecting other barriers to development is appropriate.

- **Delays to project development timescales or delay to timescales for completing transmission reinforcements.** We are assuming there is no extension of average project development timescales or delays to transmission reinforcements.

- **Dynamic impacts.** We do not make any assumption about the amount of additional generation brought forward by CAP148. However we assume that any reduction in capacity because of planning or wider delays causes an equivalent amount of capacity to re-enter the planning process.

4.6.1. Expected profile of generation

Using these assumptions, the volume of generation we expect to take advantage of CAP148 is shown in the table below. It can be seen that the annual increases in generation capacity are relatively modest, with projects typically able to connect a year or two sooner than would otherwise have been the case.

*Table 4.4: Additional Capacity (MW) brought forward by CAP148*

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>3 year lead time</td>
<td>768</td>
<td>627</td>
<td>374</td>
<td>799</td>
<td>756</td>
<td>661</td>
<td>0</td>
</tr>
<tr>
<td>4 year lead time</td>
<td>0</td>
<td>772</td>
<td>487</td>
<td>799</td>
<td>756</td>
<td>661</td>
<td>0</td>
</tr>
</tbody>
</table>
5. **NETWORK ISSUES**

5.1. **Overview**

In light of our consideration of eligible generation volumes, this section considers the consequences of the increase in generation volumes for networks. We consider costs in two areas.

- Operational costs, including constraint costs and the need to hold reserve.
- The efficiency and cost of network investment.

5.2. **Operational Costs**

Operational costs comprise a number of factors:

- The frequency of constraints.
- The cost of relieving those constraints (comprising bids and offers).
- Any additional costs, for example holding reserve generation, associated with the change in the generation mix.

5.2.1. **Constraint costs**

National Grid as System Operator (SO) will take actions for two reasons:

- Energy balancing, which is the residual purchasing and selling of electricity to keep transmission system demand and supply in balance in real time.
- System balancing, which involves ensuring the system remains within safe operating limits and that the pattern of generation and demand is consistent with any system transmission related constraints.

A transmission related constraint arises where the system is unable to transmit the power supplied to the location of demand due to congestion at one or more parts of the transmission network. In the event that the system is unable to flow electricity in the manner required, the SO will take actions in the market to increase and decrease the amount of electricity at different locations on the network.

5.2.2. **The frequency of constraints**

The frequency of constraints will be determined by a number of factors.

- The pattern and location of generation and demand – which will determine power flows across the network.
• The capability of the transmission network, particularly across key system boundaries.

• Operating decisions by generators (which are in turn based on fuel and other costs) and contracting decisions by suppliers which will also determine the pattern of power flows.

• The programme of outages required to maintain or upgrade the network, particularly across key system boundaries.

It is therefore difficult to predict the frequency of constraints with any degree of accuracy. The main drivers for the purposes of the analysis of CAP148 are likely to be:

• The outage program agreed by National Grid and Transmission Licensees.

• In the short term, how frequently thermal plant in Scotland, most notably Longannet, Cockenzie (Coal) and Peterhead (gas) run, and in the longer term if and when plant which has opted out of the Large Combustion Plant Directive (LCPD) closes.

The CAP148 working group conducted high-level indicative analysis on the potential impact of the proposal\(^\text{10}\) on constraints. It assumed that each incremental MW of DTEC would be fully constrained 15% of the time on average. National Grid’s analysis also recognised that relatively small increments in generation could have considerable consequences for the incidence of constraints. It suggested that an increase of 500MW would see DTEC generation being constrained 35% of the time.

Given the public unavailability of any additional analysis, we have used these figures as our central case assumptions. However we note that users are able to change the frequency of constraints and threshold at which the model defaults to the higher constraint frequency.

5.2.3. Historic and forecast constraint costs

The cost of resolving constraints will be determined by the bids and offers submitted into the balancing mechanism by generators or the price at which National Grid is able to strike longer-term ancillary service contracts. We note that Ofgem recently launched an investigation into balancing mechanism bidding behaviour by Scottish plant.

The table below shows the outturn and forecast levels of constraints since BETTA go-live. There are series of boundaries on the network where constraints can be experienced. National Grid’s constraint forecasting methodology (explained in detail in an appendix to the recent consultation on SO incentives) groups constrained boundaries into 3 categories. There are up to 8 boundaries which cause costs within Scotland (because of both export or import constraints and particularly under outage conditions) which are treated together, the

\(^{10}\) Contained in Annex 11 of the Working Group Report
series of boundaries in England and Wales are aggregated and the Cheviot boundary (the former interconnector circuits between England & Scotland) is a critical constraint boundary and treated on an individual basis. The total volume of constraint costs seen and forecast across key boundaries is shown in the table below.

Table 5.1: Historic & forecast constraint costs (£m)

<table>
<thead>
<tr>
<th></th>
<th>2005/06 outturn</th>
<th>2006/07 outturn</th>
<th>2007/08 forecast</th>
<th>2008/09 forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td>England &amp; Wales</td>
<td>19.6</td>
<td>28.6</td>
<td>33</td>
<td>19</td>
</tr>
<tr>
<td>Cheviot Boundary</td>
<td>31.6</td>
<td>24.9</td>
<td>35</td>
<td>67</td>
</tr>
<tr>
<td>Within Scotland</td>
<td>28.5</td>
<td>54.6</td>
<td>22</td>
<td>39</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>79.7</strong></td>
<td><strong>108.1</strong></td>
<td><strong>89</strong></td>
<td><strong>125</strong></td>
</tr>
</tbody>
</table>

Source: National Grid- System Operator Incentives

The upgrade of the Cheviot Boundary circuits was approved by Ofgem under the Transmission Investment for Renewable Generation (TIRG) project in 2003. Work has only recently started and will continue during summer outage periods over the next 5 years. National Grid has developed a probabilistic forecast of constraint prices for 2008/09 across the Cheviot boundary based on various assumptions about bid and offer prices. This is shown in the tables below for both summer and winter.

Table 5.2: Forecast Cheviot constraint costs winter 2008/09 (£m)

<table>
<thead>
<tr>
<th></th>
<th>Low Scenario (20% probability)</th>
<th>Central Scenario (60% probability)</th>
<th>High Scenario (20% probability)</th>
<th>Weighted Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Av Scottish Bid Price</td>
<td>&lt;14.9&gt;</td>
<td>&lt;15.7&gt;</td>
<td>&lt;17.8&gt;</td>
<td>&lt;15.9&gt;</td>
</tr>
<tr>
<td>Replacement Price</td>
<td>75.0</td>
<td>83.9</td>
<td>92.8</td>
<td>83.9</td>
</tr>
<tr>
<td><strong>Constraint Price</strong></td>
<td><strong>60.1</strong></td>
<td><strong>68.3</strong></td>
<td><strong>75.0</strong></td>
<td><strong>68.0</strong></td>
</tr>
</tbody>
</table>

Source: National Grid

Table 5.3: Forecast Cheviot constraint costs summer 2008/09 (£m)

<table>
<thead>
<tr>
<th></th>
<th>Low Scenario (20% probability)</th>
<th>Central Scenario (60% probability)</th>
<th>High Scenario (20% probability)</th>
<th>Weighted Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Av Scottish Bid Price</td>
<td>&lt;13.0&gt;</td>
<td>&lt;13.8&gt;</td>
<td>&lt;14.5&gt;</td>
<td>&lt;13.8&gt;</td>
</tr>
<tr>
<td>Replacement Price</td>
<td>57.3</td>
<td>65.0</td>
<td>76.4</td>
<td>65.7</td>
</tr>
<tr>
<td><strong>Constraint Price</strong></td>
<td><strong>44.3</strong></td>
<td><strong>51.2</strong></td>
<td><strong>61.9</strong></td>
<td><strong>51.9</strong></td>
</tr>
</tbody>
</table>

Source: National Grid
We recognise that constraints arise on system boundaries other than between England and Scotland and that the costs associated with relieving those constraints will differ. We have structured the model such that the user may specify a different constraint cost by Transmission Asset Owner (TO) area. However, given that a large proportion of eligible DTEC generation is likely to be located in Scotland, we consider that basing our central constraint cost assumption on the boundary which is likely to be constrained most frequently is appropriate.

National Grid’s analysis for the CAP148 Working Group used a constraint cost of £65/MWh, a load factor of 40% and assumed that only conventional generation was constrained.

*The risk of constraining renewables to bring on renewables*

A key aim of CAP148 is to connect greater volumes of renewable generation. There is a risk that, particularly in areas of the country with localised constraints, a situation could arise where renewable generation was constrained to enable renewable generation to enter the market. This is clearly neither efficient or economic and would impact on the costs associated with CAP148.

In the majority of cases, we would expect thermal plant to be constrained down to allow DTEC generators to generate. However, in North-West Scotland ahead of the completion of the Beauly-Denny upgrade, there is a risk that, because of a lack of alternatives, hydro generation could be constrained. We have discussed this situation with National Grid who consider that, were it to occur, it would be expected to be a temporary situation and dependent on the volume and location of DTEC generation. As such we have made no allowance for it.

5.2.4. Impact of wind on the system

As the volumes of renewable generation, and wind generation in particular, increase there are likely to be several possible impacts.

- **System operation** – The increased uncertainty over the level of output may suggest that the SO needs to take more actions to manage the level of demand and generation or contract for greater volumes of reserve services\(^\text{11}\).

- **Existing generation** – Existing generators patterns of operation may shift, particularly where they are required to provide system support services. This might

\(^{11}\) National Grid has stated: “balancing costs would be expected to rise in line with the wind portfolio. This is because, an increase in generation from sources of unpredictably fluctuating output is expected to result in increased holding of System Reserve and procurement of services to manage system frequency. We have previously estimated that for the case with 8000MW of wind needed to meet the 10% renewables target for 2010, balancing costs can be expected to increase by around £2 per MWh of wind production.”.
imply a more variable output regime and a reduction in the load factor of existing plant.

The exact impact of wind generation on reserve is difficult to forecast and will be a function of many factors, including the level of wind penetration and operating decisions of other plant\(^\text{12}\). We note that National Grid’s initial assessment for the 2008/09 SO incentives indicates that for the additional volumes of wind generation connecting in 2008/9 there will be an increase of £5.5m - £9.5m. For the purposes of this study we are assuming that an additional GW of capacity will give rise to £4m of additional reserve costs.

5.3. Network investment

CAP148 proposes both to connect generation to the network more quickly on average than is the case today and to provide transmission licensees with more freedom in managing the connection of that volume of generation. This process could have the following impacts.

- **More efficient network investment.** National Grid’s ‘invest then connect’ approach applies deterministic standards which take little, if any, account of generation technology or location. It could be argued that CAP148 will provide transmission licensees with greater discretion over network investment and management which may lead to more efficient investment decisions and appropriate trade-offs between operational and capital costs (particularly if a suitable supporting incentive package is put in place). For example, it could be argued that investing in the network based on a capacity factor which is much higher than the average load factor of intermittent generation plant may lead to unnecessary investment and that this situation could be avoided under CAP148.

- **Stronger incentives on transmission companies to deliver on time.** Increasing the amount of risk born by transmission licensees (from zero) may impact on their behaviour. The risks of penalties (either reputational or under incentive schemes) for late delivery of capacity might incentivise TOs to find more innovative or effective ways of providing capacity.

- **Incurring costs at an earlier stage.** If TOs are incentivised or are required to undertake transmission work more quickly than would otherwise have been the case, customers will begin paying for that investment at an earlier point. If costs are being assessed relative to the current baseline, then this will result in a cost increase (equal to the costs of financing the investment for the additional period). If however one considers that the need for the investments has been accepted (as Ofgem sanctioned them under the TIRG or TPCR processes) then this could be argued to be beneficial.

\(^\text{12}\) Email from Chris Bennett of National Grid to BWEA members.
• *Increased opex costs.* It could also be argued that there will be an increase in operational costs if licensees seek to procure more, or reallocate existing, resources as a result of CAP148. We note that transmission companies face a licence condition to operate in an economic and efficient manner and that there is regulatory oversight of any costs incurred.

• *Perverse incentives.* It could be argued that CAP148 may create incentives to re-schedule network investments to make sure TOs meet their obligations under CAP148. In theory this may disadvantage non-eligible generators.

5.4. **Central case**

In light of discussions above, we adopt the following as our central case:

• We assume that if less than 500MW of generation purchases DTEC in a given year constraints occur 10% of the time and that if greater than 500MW of DTEC is purchased constraints occur 35% of the time\(^\text{13}\).

• We assume an annual increase in reserve and ancillary service costs of £4m for each additional GW of capacity.

• We assume an average cost of resolving constraints of £60/MWh – having taken account of summer and winter costs across the Cheviot boundary.

• We attribute no cost or benefit to the impact on CAP148 on network investment, though we consider that the benefits of providing additional flexibility to network companies could potentially be significant.

5.5. **Assessment of network issues**

Tables 5.5 below shows our estimate of incremental costs on an annual basis, using the additional capacity assumptions shown previously in table 4.4.

\(^{13}\) We note that this is an area where little data is available and may benefit from greater scrutiny.
<table>
<thead>
<tr>
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</tr>
</thead>
<tbody>
<tr>
<td>Reserve/Ancillary Service Costs</td>
<td>3.09</td>
<td>1.95</td>
<td>3.20</td>
<td>3.02</td>
<td>2.64</td>
<td>0</td>
</tr>
<tr>
<td>Constraint Costs</td>
<td>54.11</td>
<td>10.28</td>
<td>58.41</td>
<td>56.26</td>
<td>49.93</td>
<td>0</td>
</tr>
<tr>
<td>Annual Cost</td>
<td>57.20</td>
<td>12.23</td>
<td>61.60</td>
<td>59.29</td>
<td>52.58</td>
<td>0</td>
</tr>
</tbody>
</table>
6. **IMPACT ON COMPETITION & THE WHOLESALE MARKET**

6.1. **Overview**

Having considered the likely volumes and impacts on networks, we now consider the likely consequences of CAP148 on the energy market. Drawing firm conclusions is again difficult, as is disaggregating the impacts of CAP148 and other ongoing factors that influence market behaviour. This section addresses three main issues:

- The impact of CAP148 on energy prices.
- The impact on the operation of the renewables obligation.
- The environmental benefits likely to result from CAP148.

6.2. **Energy market competition and prices**

The impact of CAP148 on prices is uncertain. We consider that there are a number of possible impacts, discussed below. The extent to which these impacts are felt will depend on a range of factors, including whether they are passed on to end consumers.

- **Displacing marginal generation.** Other things being equal an increase in the volume of renewable generation connected to the network would be expected to put downward pressure on wholesale energy prices. Assuming that suppliers seek to contract for a majority of their power from the cheapest provider and, given they are likely to be able to realise a percentage of the value of a ROC from contracting with renewables, it would be expected that any new DTEC generation would displace marginal plant, creating a cost saving equal to the difference in the marginal costs of the generation technologies.

- **The need for reserve.** However the argument above will be weakened by the requirement that some fraction of that marginal plant which the additional generation displaces is required for reasons of system security. These generators will need to recover costs while running for fewer hours, suggesting that the costs of striking ancillary service contracts or the prices posted in the balancing mechanism might be greater. While National Grid may be able to partially mitigate costs through contracting strategies, there is a risk that price increases to customers may result. This issue was considered in the previous section.

- **Reducing renewable generator risk.** If CAP148 makes the investment environment for renewable generators more stable, the cost of capital for renewable generation projects may be expected to fall, leading to cost savings which should be passed on to customers.
Our wholesale price assumption is based on the difference between the marginal cost of the source of energy displaced and the marginal cost of the renewable energy displacing it\textsuperscript{14}.

6.2.1. Additional Charging revenue

Transmission Network Use of System (TNUoS) charges are designed to recover a fixed amount of revenue that in turn is based on a forecast of the TO’s investment requirements. Therefore increasing the number of generators that pay charges will lead to increased receipts to National Grid. Given that the vast majority of CAP148 generation is located in Scotland, the area with the highest TNUoS charges, this impact could be material. The increased revenue will be recycled to all system users via lower TNUoS charges with a one year time lag. It has been argued that this will provide a cost saving. However, as there will be no impact on the marginal cost of generation, we do not consider that this will impact on prices.

6.3. Impact on the Renewables Obligation

The Government’s key policy measure to support renewable generation is the renewables obligation. The Renewables Obligation (RO) requires licensed electricity suppliers to source a specific and annually increasing percentage of the electricity they supply from renewable sources (The current level is 7.9\% for 2007/08 rising to 15.4\% by 2015/16) or pay a buy-out price for failing to meet their obligation. Any buy-out payments are recycled through a buy-out fund to parties that have met the obligation, increasing the price.

Under the existing system, the costs of the RO are fixed. Therefore it could be argued that by increasing the volume of generation connected for a given pot of money, CAP148 would increase the efficiency of the RO. However, there are proposals to reform the RO. These proposals include providing differential levels of support depending on the technology (banding) and building ‘headroom’ into the target. The aim is to ensure that incentives to invest in renewable generation do not become weaker as greater generation volumes connect. Under a RO structured in this way, if sufficient generation connects such that the headroom mechanism is triggered, it could be argued that costs to customers will increase.

Whether this cost is included in an assessment of CAP148 will depend on:

- The volume of renewable generation that connects to the network, both under a base case scenario and as a result of CAP148.
- How any headroom mechanism will be structured.
- Whether the generation volume is sufficient to trigger that mechanism.

It will also importantly depend on the counterfactual used in the assessment:

\textsuperscript{14} We have drawn these figures from the recent study by Redpoint Consulting.
• If the need to meet the European Commission’s 2020 target for renewable generation is accepted, then it would seem appropriate to consider how the target can be met at least cost. The assessment then needs to consider whether CAP148 increases the likelihood of meeting the target and the costs of so doing, compared with other, possibly more costly, ways in which the target may be reached.

• If it is assumed that the Commission and Government’s desire is to meet the target as quickly as practicable, then it is necessary to consider CAP148’s role in achieving this.

• However, if no assumptions are made about the need to meet the target, then it can be argued that the connection of any volume of renewable generation will increase costs to consumers relative to the existing baseline. It would, however, be somewhat cynical for the Government to accept the renewables target on the assumption that various obstacles will prevent its achievement and thereby save the UK some costs.

Because of the uncertainty over the exact structure of any revised RO we do not include additional costs in our central case.

6.4. Carbon savings

The carbon saving associated with DTEC will be dependent on:

• The extent to which low-carbon generation that uses the product displaces thermal units.

• The type of plant assumed to be displaced.

If it is assumed that any energy generated by DTEC holders displaces an equal amount of energy which would otherwise have been produced from carbon emitting generation\(^{15}\), then the expected volume of carbon saved will be equal to the total annual output of DTEC generation multiplied by an average load factor. However, if thermal plant is required to be held as reserve, or if its pattern of operation shifts such that it produces a greater volume of emissions, this impact will be partially offset.

Various plant types create different levels of carbon emissions. It is therefore necessary to consider the types of plant which are displaced. The table below shows the level of emissions by type of fuel.

\(^{15}\) Because of the economics and location of nuclear generation it seems unlikely that nuclear generation would be displaced.

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Emissions per fuel type</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>910g/kWh</td>
</tr>
<tr>
<td>Gas</td>
<td>360g/kWh</td>
</tr>
<tr>
<td>Nuclear</td>
<td>5g/kWh</td>
</tr>
<tr>
<td>---------</td>
<td>--------</td>
</tr>
</tbody>
</table>

Source: Carbon Trust

The DTI's Digest of UK Energy Statistics (Dukes) 2005 edition assumes that for each unit of electricity generated from fossil fuels, 53% comes from gas and 47% coal. However we recognize that the share of gas generation within the fuel mix has increased since that time. That said, we note that given their operating regimes and flexibility, it might be expected that coal fired generation would be constrained more frequently than gas. This may be particularly true in Scotland where Longgannet and Cockenzie represent a large proportion of installed capacity and are frequently constrained. In our base case scenario we are using a 50/50 ratio between coal and gas. The model provides the user with an ability to vary this ratio.

6.4.1. Other greenhouse gas savings

We recognise that by displacing carbon producing generation, there may be reductions in other potentially harmful emissions. It is likely that there would be some reduction in sulphur dioxide and nitrous oxide emission, though we have not sought to quantify or cost any such savings.

6.4.2. The cost of carbon

A cost of carbon needs to be applied to the volume of emissions savings to translate it into a cost. Ofgem recently published an open letter\(^\text{16}\) discussing the appropriate role of the cost of carbon in policy appraisal. While that letter noted the need to consider carbon savings as part of any assessment, it did not propose a value. It noted that values under the EU ETS and the shadow price of carbon should be used.

For the purposes of our assessment we use the shadow price of carbon as set out in the Treasury Green Book.

6.5. The appropriate discount rate

A further relevant factor for the assessment is the rate at which costs and benefits are discounted. There are largely two options which can be used:

- The social discount rate/ the social rate of time preference
- A private discount rate such as National Grid’s allowed cost of capital

This assessment uses the social discount rate of 3.5% as set out in the Treasury Green Book. The impact of using National Grid’s cost of capital is shown in Appendix 4.

6.6. **Central Case**

Our central case assumptions in this area are:

- DTEC generation creates a one for one displacement of conventional generation.
- Conventional generation is displaced in the ratio 50:50 between coal and gas.
- There is a reduction in wholesale prices based on the difference between marginal costs of renewables and displaced generation sources.
- The shadow price of carbon of (£25/MWh) should be used to cost emissions savings.
- No other benefits from reduced emissions arise.
- Costs and benefits are discounted at the Treasury’s Green Book Social Cost of Carbon of 3.5%.

6.7. **Assessment of benefits**

Table 6.2 shows the benefit expected to arise from CAP148 on an annual basis. Figures are shown in money of the relevant year (i.e. are not discounted).

*Table 6.2: Annual benefits resulting from CAP148 (£m) – 4 year lead time*

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Decrease in</td>
<td>2.37</td>
<td>1.49</td>
<td>2.45</td>
<td>2.32</td>
<td>2.03</td>
<td>0</td>
</tr>
<tr>
<td>wholesale prices</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carbon Savings</td>
<td>43.15</td>
<td>27.74</td>
<td>46.47</td>
<td>44.85</td>
<td>39.99</td>
<td>0</td>
</tr>
<tr>
<td>Annual Benefit</td>
<td>45.51</td>
<td>29.24</td>
<td>48.92</td>
<td>47.16</td>
<td>42.02</td>
<td>0</td>
</tr>
</tbody>
</table>
7. **Qualitative Costs & Benefits**

7.1. **Overview**

The proposal is likely to have a series of other impacts. However, many of these are subjective and seeking to quantify them would be difficult or overly dependent on assumptions. This section discusses these issues.

7.2. **Costs**

7.2.1. **BSUoS volatility**

It has been suggested that CAP148 could give rise to greater unpredictability in balancing charges, which could impair supply market competition. Again, this is a function of the charging regime that will be put in place. If the charge is not fully reflective of increased operational costs, then the overall level of costs, which will flow through Balancing Services Use of System (BSUoS) charges, will also increase. However, simply because the volume being recovered is higher, it is not clear that increased volatility necessarily follows. Given that there is a 3 year lead time for generation connections, the level of generation should be easy to forecast (and arguably more certain than at present).

7.2.2. **Distortions to competition**

Were CAP148 approved under the existing BSUoS arrangements, it could be argued that existing users would subsidise new entrants, which could distort competition. This might in turn increase risk in the market more generally. This argument appears valid, though it is interesting to note that the non-locational nature of BSUoS charges contains several implicit cross-subsidies. For example, any plant which benefitted under the BETTA transitional arrangements could be argued to benefit, as could any plant located in the North of the country.

7.2.3. **Constraining the development of ‘better’ options**

One interesting argument is that the approval of CAP148 could constrain the development of an option which could address the current connection difficulties more effectively. This argument probably depends on whether CAP148 is viewed as an enduring solution, which we do not consider represents the view of either the proposer or the working group.

7.3. **Benefits**

7.3.1. **Administrative benefits for TOs**
A key benefit of the proposal is that it gets rid of the so-called GB queue. Assuming a generator is happy to purchase DTEC, there is no incentive to apply for capacity ahead of need to benefit from a first-come-first-served system. It will simply request capacity three years prior to the point at which it expects to need it.

This might be expected to provide significant administrative benefits for transmission licensees, who currently spend considerable resource on managing agreements, optimising the need for reinforcements and considering the appropriate basis on which to plan investment.

7.3.2. Government/ Scottish Exec targets/ European targets

Assuming CAP148 leads to the connection of greater volumes of renewable generation at an earlier point than would otherwise be the case, progress towards the Government, Scottish Government and binding European level renewable targets will be relatively quicker. In addition if it improves certainty and/or reduces risk for developers then the likelihood of meeting those targets is likely to be greater.

7.3.3. Supply security

It could be argued that the earlier connection of wind generation will enhance diversity and security of supply. However we note that views on the extent to which wind generation contributes to security of supply differ.

7.4. Costs or benefits

This section discusses factors which may be viewed as costs or benefits of the proposal.

7.4.1. Certainty/risk for generation developers

Our discussions with various parties have revealed varying views on the impact of CAP148 on risk.

By more effectively aligning planning timescales and timescales for delivering transmission access, a key argument in favour of the proposal put forward by stakeholders is that it will stimulate the market for renewable generation and considerably increase certainty. However parties have also suggested that the proposal would undermine investment in conventional generation technologies, by increasing the risk over when plant may be able to run. Some have extended this argument and suggested that this may impact adversely on security of supply. It is not clear that CAP148 would increase income risk if generators are paid when they’re unable to generate.

A further view is that the proposal could exacerbate some of the existing problems being experienced by all generators in gaining access. It has been suggested that the prospect of
being constrained more frequently (and the knowledge that this will be the case) may serve to inefficiently extend the life of existing plant.

7.4.2. Stranded asset risk

If the point above is accepted, there could be a risk that transmission capacity will not become available when it would otherwise have done so and, potentially, that unnecessary investment in transmission capacity could be undertaken, creating stranded assets. However, a counter argument is that, by reducing the uncertainty over the generation background (most of which is made up of renewable generation) the ability for the transmission licensees to make efficient investment decisions will increase, reducing stranded asset risk.
8. **ASSESSMENT & CONCLUSIONS**

8.1. **Overview**

This section brings together the various elements discussed in the preceding chapters to reach a view on the overall costs/benefits which might be expected to be associated with CAP148.

8.2. **Results**

The table below shows the net present value of costs/benefits of CAP148 based on a 3 and 4 year lead time.

*Table 8.1: Costs/ Benefits resulting from CAP148 (£m) 4 year lead time*

<table>
<thead>
<tr>
<th>Year</th>
<th>2013/14</th>
<th>2014/15</th>
<th>2015/16</th>
<th>2016/17</th>
<th>2017/18</th>
</tr>
</thead>
<tbody>
<tr>
<td>Costs</td>
<td>&lt;57.20&gt;</td>
<td>&lt;12.23&gt;</td>
<td>&lt;61.60&gt;</td>
<td>&lt;59.29&gt;</td>
<td>&lt;52.58&gt;</td>
</tr>
<tr>
<td>Benefits</td>
<td>45.51</td>
<td>29.24</td>
<td>48.92</td>
<td>47.16</td>
<td>42.02</td>
</tr>
<tr>
<td>Net Cost/Benefit</td>
<td>&lt;11.69&gt;</td>
<td>17.01</td>
<td>&lt;12.68&gt;</td>
<td>&lt;12.12&gt;</td>
<td>&lt;10.56&gt;</td>
</tr>
</tbody>
</table>

When discounted the **NPV is a cost of £22.92m**

*Table 8.2: Costs/ Benefits resulting from CAP148 (£m) 3 year lead time*

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Costs</td>
<td>&lt;55.16&gt;</td>
<td>&lt;47.78&gt;</td>
<td>&lt;9.39&gt;</td>
<td>&lt;61.60&gt;</td>
<td>&lt;59.29&gt;</td>
<td>&lt;52.58&gt;</td>
</tr>
<tr>
<td>Benefits</td>
<td>44.47</td>
<td>36.99</td>
<td>22.45</td>
<td>48.92</td>
<td>47.16</td>
<td>42.02</td>
</tr>
<tr>
<td>Net Cost/Benefit</td>
<td>&lt;10.69&gt;</td>
<td>&lt;10.78&gt;</td>
<td>13.06</td>
<td>&lt;12.68&gt;</td>
<td>&lt;12.12&gt;</td>
<td>&lt;10.56&gt;</td>
</tr>
</tbody>
</table>

When discounted the **NPV is a cost of £34.70m**
8.3. Conclusion

The analysis above suggests that the expected net present value of CAP148 would be expected to be slightly negative given existing system conditions and observed prices. However these conclusions are highly dependent on the assumptions chosen. As shown in Appendix 4, altering assumptions produces a range of outcomes between a net benefit and a greater net cost.

For example, if it is assumed that more coal than gas generation will be displaced by the generation brought forward by CAP148 and/or if it is considered that either the frequency of constraints or cost of resolving constraints will be lower than the forecast in our central case, the impact of CAP148 is likely to be positive.

We also consider that there are a series of qualitative factors, including the benefits of providing greater flexibility and discretion to National Grid and transmission licensees in undertaking network investment, that may be expected to yield additional benefits which are not included within these results. CAP148 would also facilitate the achievement of the Government and Scottish Government’s targets for the proportion of energy sourced from renewable generation and the achievement of binding EU level targets.
APPENDIX 1: BACKGROUND & CONTEXT

Overview

This appendix provides background and context to the wider discussion on transmission access. It discusses the interrelationship between networks and the wholesale market, explains the current challenges being faced by transmission access arrangements and provides an overview of the rules governing the market. It also discusses a relevant comparator to the debate surrounding CAP148.

The transmission network and wholesale market

The transmission network transfers electricity in bulk at high voltages from generators to large industrial users and to local distribution networks. The Transmission Network is owned by 3 companies, National Grid Electricity Transmission (NGET) in England and Wales, Scottish Power Transmission Limited (SPTL) in Southern Scotland and Scottish Hydro Electric Transmission Limited (SHETL) in Northern Scotland. The network is operated throughout GB by NGET (the so called “system operator (SO)”).

The wholesale market is based on suppliers contracting with generators that can supply them with power at the lowest cost, with the power flowing over the transmission network. An efficiently functioning transmission network therefore plays an important role in facilitating competition in the wholesale market.

The current challenges

Much of the transmission network was built in the 1960s in a period when the demands placed on it were much different from today. The move away from infrequent large increments of thermal generation, to numerous requests for capacity from much smaller, remote (from a transmission network perspective) renewable generators has created new challenges for both the transmission network (and the associated planning system).

During and immediately after the British Electricity Transmission and Trading Arrangements (BETTA) process over 12GW of renewable generation applied to connect to the Scottish transmission networks alone (with more seeking connection at distribution voltages). In addition large volumes of on- and offshore-wind generation is forecast to connect in increasing volumes in England and Wales over the next decade. To accommodate this increase in generation and to account for the different operating characteristics of renewable generation, both networks and the regulatory regime will need to adapt.

In the majority of cases there is a clear need for upgrades and Ofgem has accepted that customers should pay for the required reinforcement as part of the Transmission Investment
for Renewable Generation (TIRG)\textsuperscript{17} and Transmission Price Control Review (TPCR)\textsuperscript{18} processes. However, building new transmission lines, particularly in rural areas or areas of outstanding natural beauty, creates difficult planning challenges as parties are often vocal in their opposition to new or bigger lines. In practice, securing planning consents for new upgrades is a lengthy process, often involving public enquiry and a need to redesign upgrades (for example to put proportions of lines underground).

The existing arrangements for securing network capacity, discussed in more detail below, mean that new generators must wait until all these upgrades are finished before they can connect. Therefore delays in planning and building new transmission lines also delay the connection of new generation. To illustrate, an applicant applying to connect to/use the transmission network in most of Scotland, Wales or Northern England today could expect to receive a connection date of circa 2018 and potentially later.

The Government has committed to a binding European level target that 20\% of EU energy consumption is met from renewable generation by 2020. This is likely to require at least 40\% of electricity to be generated from renewable technologies and could require as much as 30GW of additional capacity to be installed. Therefore delaying the time at which renewable generation can enter the market has a substantial negative impact on progress towards this target.

Government, Ofgem and the industry have been working to develop solutions to the various problems associated with difficulties in securing capacity and the so-called GB Queue. Connection and Use of System Code Amendment Proposal\textsuperscript{148} (CAP148), which this document assesses, is a proposal to revise the current rules in an attempt to ease the severity of the current situation.

\textbf{Existing arrangements for allocating capacity}

The current arrangements for acquiring transmission capacity are based around the concept of first-come-first-served. Any generator wishing to connect to and use the network (or to increase their existing capacity holding) must apply to National Grid and wait until specified upgrade works have been completed by the relevant Transmission company(ies). Generators who have already been through this process have an ongoing right to use the network.

While a new generator is waiting to receive its access rights it is required to provide financial security against the costs incurred by transmission companies in constructing the works required to facilitate the connection, to ensure that the system complies with the relevant planning and security standards (see below) and to insure against the risk of unnecessary investment if the generator does not subsequently connect to the network. Once the generator is connected and starts paying for use of the network, the requirement to provide security falls away and is replaced by a rolling annual obligation to pay transmission charges.

\textsuperscript{17} See http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/TIRG/Pages/TIRG.aspx
\textsuperscript{18} See http://www.ofgem.gov.uk/Networks/Trans/PriceControls/Pages/PriceControls.aspx
The GB Security and Quality of Supply Standards

The transmission licensees are required to comply with the requirements of the GB Security and Quality of Supply Standards (GB SQSS) when developing and, in the case of NGET, operating, the transmission system. Through a combination of deterministic and economic factors, the GB SQSS defines the amount of infrastructure that must be available to connect any given level of generation and demand. It therefore limits the amount of demand or generation that can connect to the network ahead of reinforcements being completed.

Where a part of the network does not comply with the requirements of the GB SQSS, the relevant transmission licensee must approach Ofgem and seek derogation against the requirement to comply. Several circuits, most notably the circuits across the Cheviot boundary (the former interconnector between England and Scotland) are currently subject to derogation.

The Connection and Use of System Code (CUSC)

The Connection and Use of System Code (CUSC), which all large generators are required to sign, sets out the standard commercial terms between generators (and other network users) and National Grid. The CUSC is a modifiable document and any signatory to the CUSC can propose a change. A change proposal will be assessed by a Working Group, referred to the governing body (the CUSC Panel) who will vote on the proposal and an amendment report prepared by the Working Group will then be submitted to Ofgem. Ofgem must decide whether a proposal better facilitates achievement of the applicable CUSC objectives and, if so, decide whether it is consistent with its primary and wider statutory duties.

The CUSC objectives are:

- The efficient discharge by the licensee of the obligations imposed upon it under the Act and by this licence.
- Facilitating effective competition in the generation and supply of electricity, and (so far as consistent therewith) facilitating such competition in the sale, distribution and purchase of electricity.

System operation and constraint costs

The wholesale market is based on bilateral contracting between generators and suppliers for the delivery of energy. While the majority of energy is delivered this way, there is inevitably a mismatch which must be managed. This role falls to National Grid as the System Operator. It is responsible for the ‘residual balancing’ of the network and ensuring that supply is constantly equal to demand. It performs this role by managing the levels of generation and demand on the network through contracts (for example, for reserve services).
or by accepting bids and offers in the balancing mechanism – effectively an auction in which generators or large demand customers bids indicate their willingness to vary output in a given half hour. The costs of balancing the network are recovered through Balancing Services Use of System (BSUoS) charges as a uniform commodity charge.

Constraints can arise for energy or system reasons. A transmission related constraint (which can be caused by export or import problems) arises where the system is unable to transmit the power a generator is contracted to supply to the demand it is contracted to meet (or vice versa) due to congestion at one or more point on the transmission network. In the event that the system is unable to transport electricity, the SO will take actions to increase and decrease the amount of electricity at different locations on the network. The exact way in which a constraint is managed depends on a number of factors including the nature of the flows on the transmission system, the local level of generation output, the cost of alternative options for relieving the constraint and the local level of system demand.

The transmission network, constraint costs and the wholesale market

In congested areas, there is a trade-off between the level of constraints and the volume of generation connected. Other things being equal, greater volumes of generation connections are likely to create more frequent constraints and may increase the costs associated with resolving those constraints. However, greater volumes of connection would be expected to increase wholesale market competition and may exert downward pressure on wholesale prices. An important trade off in considering the net financial consequences of generation connections is whether any reduction in wholesale prices more than offsets an increase in constraint costs.

Consideration of similar issues to date – transmission access under BETTA

The issues raised by CAP148 are not unique. Similar issues were considered by Ofgem in the context of allocating access rights as part of the transition to the British Electricity Transmission and Trading Arrangements (BETTA). The reasons for the decision taken by the Authority at that stage, and the extent to which the Authority considers that the reasons for that decision hold, are unclear. However, Ofgem’s interpretation of this decision will be an important consideration in assessing the impact of CAP148.

During the BETTA process, in order to ensure that no party which had an offer to use the Scottish network or England and Wales network prior to BETTA was disadvantaged, Ofgem announced that applications for connection to either network received prior to 1 September 2004 would have their access rights converted to GB rights on a 1-for-1 basis under the so-called “transitional arrangements”. As a result a strong incentive to apply for capacity was created.

This decision meant that more generation than was physically able was allowed to connect to the transmission network and that the network did not comply with the requirements of the
GB SQSS across certain boundaries (Ofgem issued derogations against the GB SQSS to the transmission companies which remain in place). As a result, DTI/Ofgem also accepted that some generators would not be able to use the network and would need to be compensated (and the energy they would have supplied replaced with energy sourced from elsewhere) and that these costs would be passed through to consumers. Many of the arguments put forward in respect of CAP148 were also put forward during the consultation process on transitional arrangements.

An Ofgem/DTI document of July 2004 set out the thinking behind this approach and its possible consequences:

“NGC’s technical report indicates that the allocation of access rights irrespective of the completion of the network investment that would, under the enduring arrangements be required prior to an applicant connecting to the network, could result in significant enduring transmission constraints (to the extent that the rate of growth of demand for capacity outstripped for a time the rate at which network capacity could be increased) at different points within Scotland and at the boundary between Scotland and England. NGC highlighted that, inevitably, longer term forecasts of constraints are uncertain, as they relied on assumptions about project completion rates, timescales for network investment and the behaviour of existing plant in Scotland and in England and Wales.

Whilst the potential path of constraint costs is a legitimate concern for Ofgem/DTI, it is not the only relevant issue. The purpose of BETTA is to promote competition in electricity wholesale markets across GB and, other things equal, reducing barriers to competition will stimulate competition (the barrier being, in this instance access to transmission capacity for potential market entrants). Further, there are trade-offs between short-term costs and long-term costs to consider in the context of transmission constraints. The incidence of constraint costs is one mechanism whereby signals can be given by market participants to transmission licensees as to the relative importance of different network reinforcements. Short-term costs can, therefore, deliver long-term benefits in more efficient network investment.”

In practice, the introduction of transitional arrangements provided a strong incentive to apply for connection and a significant number of parties, at various stages of development, requested connection offers. None of the required transmission reinforcements which were sanctioned during the TPCR or TIRG processes have been completed and the timescales for completing other reinforcements are frequently being revised further into the future. Constraint costs have been trending upwards since BETTA go-live, in part because more generation has connected to a system which does not comply with the GB SQSS.

19 See http://ofgem2.ulec.ac.uk/temp/ofgem/cache/cmsattach/8070_17404_GBaccess.pdf Paragraph 4.15 and 4.16.
APPENDIX 2: TRANSMISSION NETWORK REINFORCEMENTS

Overview

The period for which the impacts of CAP148 will be felt will be determined by the period between the date at which eligible generation connects and the date at which transmission reinforcements are completed. We summarise our understanding of the current status of transmission reinforcements below.

SHETL

The SHETL network in Northern Scotland is the least developed part of the UK transmission network and the area with the greatest volume of connection applications. It therefore requires a series of reinforcements.

The most significant is the Beauly – Denny line, which is required to reinforce the Western side of SHETL’s network. The project requires the construction of large sections of new line and presents difficult planning challenges. In part because the line runs through areas of outstanding natural beauty, there is vocal opposition to its construction. A planning enquiry is currently ongoing and SHETL forecast a completion date of October 2012 at the earliest.

Several other reinforcements are contingent on the completion of Beauly-Denny. While we understand SHETL is seeking to advance some elements of these works, the lines from Beauly – Blackhilllocks, Kintore and Dounreay, will not be completed before 2015. However, as the required work does not, as far as we are aware, require planning approval delays may be viewed as unlikely. These reinforcements will create a ring (completed by the existing Kintore-Central Belt 400kv line) which would facilitate the connection of circa 5GW of generation. Underground cables from the Western Isles could then connect to the ring and connections to Orkney and the Beatrice offshore windfarm could connect at or near Dounreay, with minimal planning issues expected.

SPTL

Our understanding is that 4 major reinforcements are needed in SPTL’s area.

Based on an assumption of planning permission being granted in early 2009, SPTL have suggested that their proportion of the Beauly – Denny line would be expected to be completed in 2013.

Work is also required on the interconnector between England and Scotland (the so called B5 Boundary). We understand consents have been received, construction contracts let and completion scheduled for summer 2009. In South-West Scotland pre-planning works are underway and Section 37 planning applications are due to be submitted shortly. Finally, in the Sloy area planning consent for the required transmission substation has been refused by
the National Park Authority. SPTL is planning an appeal in the near future and forecast an earliest completion date of 2009, depending on the outcome of a review.

Cheviot Boundary

A series of reinforcements to the former England-Scotland interconnector circuits are required. Consents have been received and work is underway during the summer period. An intensive period of outages is required to deliver an increase in capacity from the existing 2200MW to 2800MW in 2008 and 3100MW by 2010. We understand that further work (not dependent on planning consents) could increase capacity to circa 4GW.

National Grid

There is also a considerable amount of work, sanctioned through both the TPCR and TIRG processes, taking place or scheduled to take place on NGET’s transmission network. Works out to 2013/14 (for all TOs) are shown in the GB Seven Year Statement

The most significant works, in addition to the upgrades to the circuits across the Cheviot boundary, are the reinforcements in the North West of the country around Heysham (the so called Heysham ring), works in the North East around Teeside and Immingham and reinforcement work in South Wales. In addition, works are planned in the South East of the country to facilitate the connection of offshore wind generation in the Renewable Energy Zones around the Thames Gateway and off the Norfolk and Lincolnshire coasts.

Delays to transmission reinforcements

We note that were a major reinforcement to be delayed, the period for which the impact of CAP148 would be felt would also increase. While this delay would not be expected to effect the total volume of generation, it is likely that the sequential approach being taken to reinforcements would mean that a significant number of projects would, absent CAP148, face a delay. The table below provides an indicative view of the number of projects dependent on certain reinforcements.

Table A2.1: Indicative number of projects dependent on major reinforcements

<table>
<thead>
<tr>
<th>Reinforcement Number</th>
<th>Name</th>
<th>Forecast Completion Date</th>
<th>Number of dependent projects</th>
</tr>
</thead>
<tbody>
<tr>
<td>SHETL-RI-002</td>
<td>Beauly – Denny</td>
<td>2012</td>
<td>55</td>
</tr>
<tr>
<td>SHETL-RI-004</td>
<td>Beauly – Blackhillocks</td>
<td>2010</td>
<td>30</td>
</tr>
<tr>
<td>SHETL-RI-006</td>
<td>Beauly – Dounreay (Phase I)</td>
<td>2009</td>
<td>16</td>
</tr>
<tr>
<td>SPT-RI-001</td>
<td>Beauly – Denny</td>
<td>2008</td>
<td>18</td>
</tr>
</tbody>
</table>

20 Table 6.2, available from http://www.nationalgrid.com/uk/sys_07/dddownloaddisplay.asp?sp=sys_Table6_2
<table>
<thead>
<tr>
<th>Project Code</th>
<th>Location Details</th>
<th>Year</th>
<th>Quantity</th>
</tr>
</thead>
<tbody>
<tr>
<td>SPT-RI-002</td>
<td>Denny – Kincardine reactive compensation</td>
<td>2010</td>
<td>12</td>
</tr>
<tr>
<td>SPT-RI-003/004</td>
<td>Denny – Strathaven Denny</td>
<td>2014</td>
<td>35</td>
</tr>
</tbody>
</table>
APPENDIX 3 – FACTORS DETERMINING CONNECTION VOLUMES

Overview

In this appendix we give further consideration to the risks and issues which may cause a proportion of capacity not to connect to the system. This assessment has informed our view on the probability of attrition which has been applied to our base case and scenarios.

Barriers to development

There are a series of issues, in addition to an inability to secure transmission capacity, which can cause developers to abandon projects or cause material delays to the connection of renewable generation. For each of the issues, we discuss the likelihood of them causing a project to be aborted or delayed. This is a difficult process as, frequently, issues are not mutually exclusive and can interact and mutually reinforce to create even more material barriers. The major issues are set out below.

Planning

Planning has been described by the BWEA as: “the single biggest constraint on the deployment of wind power in the UK”. Consents must be secured at a local and national level and, given the often vocal opposition to renewable generation developments, planning enquiries are rarely straightforward. It is estimated that only 5% of wind farm planning applications are dealt with within the 13 week deadline for assessing major applications. The table below shows a snapshot of volumes currently at various stages of planning.

Table A3.1: Breakdown of onshore capacity awaiting decision within the UK planning system as at end 2007 (MW)

<table>
<thead>
<tr>
<th>Region</th>
<th>In planning (local)</th>
<th>In planning (section 36)</th>
<th>In planning (at appeal)</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>England</td>
<td>269</td>
<td>255</td>
<td>270</td>
<td>794</td>
</tr>
<tr>
<td>Scotland</td>
<td>1,015</td>
<td>3,880</td>
<td>225</td>
<td>5,120</td>
</tr>
<tr>
<td>Wales</td>
<td>257</td>
<td>12</td>
<td>507</td>
<td>269</td>
</tr>
<tr>
<td>Total</td>
<td>1,541</td>
<td>4,135</td>
<td>507</td>
<td>6,183</td>
</tr>
</tbody>
</table>

Source: BWEA

A considerable number of requests to construct renewable power projects are rejected at the planning stage. In addition, the time taken to reach a decision can cause significant delay to projects. The national average decision time rose from 22 months in 2006 to 24 months in 2007 (despite a fall in volumes being submitted), while the average UK approval rate has also fallen from 82% in 2004 to 62% in 2007. The table below shows the planning approval rate by region for 2007.
**Table A3.2: Approval rates per region (2007)**

<table>
<thead>
<tr>
<th>Region</th>
<th>Approval Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>England</td>
<td>62%</td>
</tr>
<tr>
<td>Scotland</td>
<td>56%</td>
</tr>
<tr>
<td>Wales</td>
<td>72%</td>
</tr>
<tr>
<td>Northern Ireland (for illustrative purposes)</td>
<td>93%</td>
</tr>
</tbody>
</table>

*Source: BWEA*

**Air defence and air traffic control radar**

The reflection from wind turbines can impact on radar readings by causing ‘clutter’. This clutter can lead to wind farms and aircraft being confused. As a result, the Ministry of Defence routinely objects to any wind project which is within the range of an Air Defence Radar. National Air Traffic Services (NATS) en-route limited also objects where a project can impact on any of their 23 air traffic control radars.

**Supply chain issues**

There is a capacity constraint in the international market for the supply and installation of wind turbines and several key component parts. This shortage and increases in input prices have driven up prices and reduced the flexibility available to generators. This may suggest that it would not be possible to source equipment were an earlier connection date available.

**Delays & financial viability**

The delays being experienced by existing projects are reducing the viability of some generation projects, as the amount by which they will benefit under the Renewable Obligation Certificate Scheme reduces and the risk associated with the investment increases.

**Regulatory developments**

Changes to regulatory arrangements have sought to promote ‘user commitment’, which involves generators financially backing requests for capacity. Given the incentives to apply speculatively for capacity in the run up to BETTA, the prospect of financial commitments may be expected to remove a free option and cause some projects not to connect.

Our discussions with a transmission company suggest that many projects which have connection dates in the relatively near term have indicated that the delays they are seeing in timescales for completing reinforcements are consistent with project development timescales and do not cause major concerns. Hence, they may have no incentive to use DTEC and, in some case, be discouraged from doing so by regulatory arrangements.

Our understanding from discussions with transmission licensees is that only a relatively small number of developers have expressed an interest in advancing connection dates, though we note that there may not be particularly strong incentives to do so.
Ability to bringing forward local works

We note that generators are only able to use DTEC if a connection to the Main Integrated Transmission Network (MITS) is in place. We have discussed the ability of transmission licensees to complete works within the CAP148 lead times with two transmission licensees.

Licensees noted that they are currently focussing their efforts on ensuring that transmission upgrades are completed as quickly as practicable. They therefore note that the ability to divert resources to carry out local works might be limited, particularly where multiple schemes applied concurrently for DTEC. Transmission licensees also noted that an extensive outage program is underway and there is limited scope for scheduling additional outages in which works can be carried out.

There is consequently some uncertainty about whether DTEC could be made available in all cases.

Risks associated with purchasing DTEC

There are a number of features of the DTEC product which may reduce its attractiveness to generators and reduce the number of parties which might seek to use it.

- A fixed commitment to pay. Generators using the DTEC product would face a liability for TNUoS charges from a given date. This differs from the existing approach where a generator can choose the date at which it begins to pay charges. This means that a DTEC generator faces an additional risk if elements of its project are delayed.

- The prospect of ‘overrun charges’. While the exact nature of charging arrangement is uncertain, were the charge for DTEC based on the incremental operational costs there would be considerable risk. Uncertainty about the volume of DTEC generation and the overall level of system constraints would mean there may be little certainty about the price a generator would pay and no ability to hedge that cost.

- The inability to switch. A generator purchasing DTEC would hold the product in perpetuity. Again, were the product charged based on operational cost, the generator would face considerable uncertainty into the future. The network is not built to be constraint free and it may therefore be reasonable to assume that the DTEC charge would often/always be above the TEC charge. Were this the case, it may not always be in a generator’s economic interest to purchase DTEC, despite the benefits of earlier connection.

- Financial securities. Many projects in Scotland have securities calculated according to the so called ‘clustering’ methodology, whereby the need to secure the costs of a reinforcement are spread between a number of parties. Were a party to move forward to take advantage of CAP148, the securities they would be required to provide could also change – creating an additional risk and potentially increased cost.
APPENDIX 4 – SENSITIVITIES

Overview

In this section we demonstrate the change in results relative to our base case from varying certain assumptions. This provides a feel for the range of outcomes which the proposal might be expected to deliver.

Using a private discount rate

If costs and benefits are discounted using a discount rate equal to National Grid’s cost of capital of 6.25%, the net present value of costs is £18.69m under the 4 year scenario and £29.16 under the 3 year scenario.

The cost of carbon

The impact of using different costs of carbon is shown in the table below. This also shows that were an EU ETS price used in the assessment, the net costs would be expected to be greater.

Table A4.1: Impact of different assumptions regarding the cost of carbon on the NPV (£m)

<table>
<thead>
<tr>
<th>Carbon Price</th>
<th>NPV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case £25/kW</td>
<td>&lt;22.92&gt;</td>
</tr>
<tr>
<td>£15</td>
<td>&lt;86.45&gt;</td>
</tr>
<tr>
<td>£20</td>
<td>&lt;54.69&gt;</td>
</tr>
<tr>
<td>£30</td>
<td>8.84</td>
</tr>
<tr>
<td>£35</td>
<td>40.61</td>
</tr>
</tbody>
</table>

Changing the cost of relieving constraints

The impact of changing the probability of attrition, based on our central case estimate, is shown in the table below.

Table A4.2: Impact of different assumptions regarding the cost of relieving constraints on the NPV (£m)

<table>
<thead>
<tr>
<th>Constraint Cost</th>
<th>NPV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case £60/MWh</td>
<td>&lt;22.92&gt;</td>
</tr>
<tr>
<td>£40</td>
<td>36.82</td>
</tr>
<tr>
<td>£50</td>
<td>6.94</td>
</tr>
<tr>
<td>£70</td>
<td>&lt;52.79&gt;</td>
</tr>
</tbody>
</table>
Changing the incidence of constraints

The impact of changing our assumption about the incidence of constraints is shown below.

*Table A4.3: Impact of different assumptions regarding the incidence of constraints above 500MW on the NPV (£m)*

<table>
<thead>
<tr>
<th>Incidence of constraint</th>
<th>NPV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case 35% above 500MW</td>
<td>&lt;22.92&gt;</td>
</tr>
<tr>
<td>25%</td>
<td>25.21</td>
</tr>
<tr>
<td>30%</td>
<td>1.14</td>
</tr>
<tr>
<td>40%</td>
<td>&lt;46.99&gt;</td>
</tr>
</tbody>
</table>

Changing the balance between coal & gas

The table below shows the impact of changing assumptions about the balance of coal relative to gas generation displaced by the additional renewable generation brought forward by CAP148.

*Table A4.4: Impact of different balances of gas and coal on the NPV (£m)*

<table>
<thead>
<tr>
<th>Constraint Cost</th>
<th>NPV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case 50/50 (Gas/Coal)</td>
<td>&lt;22.92&gt;</td>
</tr>
<tr>
<td>70/30</td>
<td>6.60</td>
</tr>
<tr>
<td>60/40</td>
<td>&lt;8.16&gt;</td>
</tr>
<tr>
<td>40/60</td>
<td>&lt;37.69&gt;</td>
</tr>
</tbody>
</table>
APPENDIX 5 - THE SOCIAL COST OF CARBON (SCC)

Overview

This appendix provides a discussion of the issues involved in determining a marginal cost for carbon emissions, and an outline of current estimates and approaches used by policy makers in a UK context.

Basic concepts

The term Social Cost of Carbon (SCC) infers an externality arising from the consumption of carbon-emitting products, i.e. a cost that is not priced in to the decision of the consumer. This negative externality differs from conventional environment costs since it is redistributed globally, across generations and, in the extreme, involves non-linear costs such as extinction. The SCC can be characterised as the total damage from now into the infinite future from an extra unit of carbon dioxide in the atmosphere, given its (uncertain) impact on the global climate and the (uncertain) resultant impact on economic activity (and how these are distributed). At its most simple level, the SCC is price per tonne of carbon dioxide emitted if no action were taken to reduce overall emissions. It is a discounted function of the costs of climate change given an assumed human contribution to this change.

Abatement costs

A policy-based approach must consider the endogenous question of abatement. There are costs involved in mitigating climate change (‘abatement costs’). The optimal target for carbon dioxide is that which ensures that the SCC is equal to the Marginal Abatement Cost (MAC).

Shadow price of carbon (SPC)

In principle, we can consider a specific stabilisation target consistent with a set of mitigation measures or assumed technological progress, and use the resulting SCC to guide pricing. The SCC in this case will be lower than the simple (‘no action’) SCC described above, due to reduced climate impacts. This involves making assumptions on the actions of other countries, and is further complicated by the (scientific) uncertainty about the SCC associated with any carbon stabilisation goal, as well as the uncertainty regarding technological innovation and policy veracity in determining the MAC profile. The endogenous SCC, i.e. that for a given stabilisation goal (level of abatement), is equal to the MAC only where the carbon market is competitive and covers all emissions. Alternatively, the Shadow Price of Carbon (SPC) is adjusted to reflect the abatement required to achieve global stabilisation, as well as national willingness to pay for reductions in emissions.
As a rule of thumb, the SCC is an absolute ‘base case’ reflection of the future damage caused by climate change and the way we measure it, while the SPC is adjusted to reflect the policy and technology environment. Applying an SPC to decision making will raise the net present value of options with lower carbon impacts.

Structure

This note has two components, namely:

- An overview of the economic issues involved in estimating the costs from climate change and the approach to estimating a marginal cost.
- A brief survey of approaches and estimates relevant to UK decision making.

Identifying and measuring the costs

Climate and impacts

The starting point for determining a monetary SCC, to then be applied to certain economic activities, must be to determine the scientific relationship between:

- Current economic activity, such as consumption and production.
- The resulting release of greenhouse gases (in this case carbon dioxide).
- The marginal impact of carbon on the climate.
- The varied costs the changing climate has upon economic activity.

Therefore, the magnitude of the SCC will depend upon the extent to which carbon emissions alter the climate over time, and the predicted impact that will have upon economic activity. Recent scientific models, such as that used in the Stern Review, include feedback effects from carbon-induced climate change to further forms of climate change. Nordhaus and Boyer (2000) pioneered the inclusion of non-economic costs, such as loss of life and social upheaval, as a possibility or more likely. These factors, ceteris paribus, increase the costs associated with carbon emissions.
The path of the SCC over time will also depend on these scientific issues. For example, if temperature is a log function of carbon dioxide emissions, the negative impacts on economic activity would have to be exponentially rising in carbon emissions (through greater concentration) in order for the SCC to be rising over time.

*Social choice is inherent in estimates*

In the standard economic approach, most widely associated with Ramsey (1928) and others, a central decision maker maximises a social welfare function (swf) that is the discounted utility of consumption over an indefinite time period. This is a social aggregate that does not rule out individual idiosyncratic deviations from the swf utility and discount rate. It incorporates necessary distributional issues that are inherent in climate change. Firstly, an assumption is required to determine the marginal utility of consumption, i.e. the extent to which individuals subjectively value each additional unit. We might intuitively expect the first dollar of consumption each day to be more valuable than the 500th, for example. More interestingly, the estimate of the SCC will depend upon the extent to which an individual values harm to others and how this is modelled in the swf. This arises directly from the central problem of climate change, that those directly or indirectly consuming carbon do not face the full cost of that consumption.

The relative weight on the economic welfare of different households over time, i.e. the pure social rate of time preference, is the discount in future welfare over time. In climate change, and other fields, it is widely debated among economists as a normative judgement. While the some criticisms of the Stern review (below), in particular of the analytical assumptions in the swf, might be applied to standard approaches for estimating the effects of climate change, the choice of discount rate is a choice-variable based on ethical considerations (and one that distinguishes the Review).

Such considerations will affect the path of the SCC over time. As time progresses, the damage to the climate will be in the nearer future and so will be discounted less. Therefore, in 20 years, the present value of the costs of climate change will be higher, increasing the SCC.

*Role of uncertainty*

The issue of uncertainty in making long-term forecasts of interrelated variables revolves around adequately pricing the risks involved. The swf must account for:

- Some model of how individuals respond to risk.
- Judgements on the nature of the risks themselves.

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21 The prices of marketed goods and services, as well as non-marketed health (e.g.), are greater in rich countries based on agents’ willingness to pay. However, the swf in the Stern Review, for example, implies that a £15 cost to a person in the UK would be equally weighted to a £1 cost to a Bangladeshi.
This latter point is considered in Figures A5.2 and A5.3 below. Considering the former, the standard approach in economics has been to use an expected utility model, whereby we assume a preference for risk among individuals at different levels of income. A requirement of this theory is that the ‘risk-preference’ is independent of the prospect at hand. The approach has been increasingly viewed as empirically flawed, with no general agreement on a satisfactory way to model risk as a result. For example, one (relatively) popular approach is to assume that agents prefer to avoid loss rather than making gains (‘loss aversion’). This would complicate the approach to modelling the costs of climate change, since the value of the probability of future catastrophes would increase, but so would the negative value of abatement costs today. Loss aversion would also alter the equity weightings, since richer countries in this dynamic would be more averse to small probabilities of calamitous losses relative to poor ones.

**Figure A5.2: Scientific and economic impacts – uncertainty in the SCC**

Figure A5.2 depicts the increasing uncertainty over time regarding the economic costs associated with current patterns of economic activity. While climate models have been improved and research advanced, there is still much uncertainty surrounding how the science of climate change can be translated into costs. This uncertainty is increased when considering non-market impacts and catastrophe events. Uncertain but extreme outcomes, under particular assumptions over individuals’ attitude to risk, raise the costs of climate change substantially.
Furthermore, as depicted in Figure A5.3, if we are attempting to calculate a SPC based on an agreed stabilisation goal (determined by the ‘uncertain’ scientific considerations in Figure A5.3) then estimating the costs of abatement based on the technological path requires various assumptions on the relationship between agreed international policies (and the credibility thereof), their impact on economic behaviour and activity, and the response new low-carbon technologies. As is well known in the economics literature, there are several market failures (knowledge spillovers, network externalities, technology lock-in, etc.) that increase such uncertainty. A risk averse society, therefore, would want to pay more than the amount that would, on average, induce a stabilising technological response in order to increase the likelihood that such a response takes place.

There is also an ‘option value’ associated with uncertainties and irreversibility regarding scientific issues and abatement. Increases in carbon emissions are irreversible over a given time frame, so while new information downplaying the impacts of climate change will allow us to increase carbon emitting activity, new information emphasising these effects will not be able to elicit a response to reduce carbon concentration. Therefore, the expectation that scientific knowledge will improve creates an option value to earlier abatement of climate change. However, there is also an option value to delaying investment in irreversible abatement, since the veracity of measures to reduce the MAC (i.e. incentives to clean technology) is unknown, but knowledge improves over time. So far as actual estimates of the SCC are concerned, there has been very little effort to measure these effects.
Different estimates relevant to UK policy

There has generally been wide variation in estimates of the SCC in academic studies, including anything up to $400/tCO_2. A survey carried out by Tol (2005) found the mean estimate to be $29/tCO_2. The Stern Review, published in 2006, has become a focal point for UK government policy towards calculating a price for carbon. Its estimates are at the upper range of other studies, because it takes specific positions on the above issues.

Stern Review of the Economics of climate change

Base case SCC

The Stern Review estimated a ‘base case’ for the SCC in 2000 prices of $85/tCO_2. This was much higher than previous government guidance because:

- Weight is given to non-market outcomes, extreme events and feedback effects in the climate.
- The equity weighting in the social welfare function reflecting how people in one country should treat the costs they impose on those in another.
- The pure rate of time preference is very low (0.001) based on the ethical judgement that society should value the small probability of a large catastrophic event.\(^{22}\)
- It uses use standard Expected Utility Theory (EUT) to assume risk adversity among various groups, and gives weight to the uncertainty surrounding the climate.

Stern uses scientific evidence that a doubling of CO_2 in the atmosphere from pre-industrial levels leads to an equilibrium temperature change of 1.5-4.5°C. The Report includes both a conservative model of climate change and a ‘High Climate’ case. In the former, mean warming to 2100 is 3.9°C and there is a 90% confidence interval of a 2.4-5.8°C rise. In the latter, where feedback effects from carbon-induced climate change lead to further warming, the mean change is 4.3°C and there is a 90% probability that it will be in the range 2.6-6.5°C. Where global temperatures are set to rise by 2-3°C, the costs to world output are 0-3% of GDP by 2100. If temperatures in the same model rise by 5-6°C, the costs are 5-10% of GDP. At the extreme end of the probability distribution function, costs are very high. The Stern Report accounts for ‘catastrophic losses’, market impacts, non-market impacts, which include an interaction with political effects.

\(^{22}\) The swf also assumes a constant elasticity for the marginal utility of consumption, resulting in the standard Ramsey equation for intertemporal choice. In this framework, the rate of return is dependent upon the growth in consumption over time and the extent to which society has aversion to intergenerational inequality.
The SCC rises over time in Stern’s approach since he asserts the expected damage increases with the level of CO₂ concentration. The extra unit of carbon thus is assumed to carry a greater cost the later it is emitted, rising by two percent each year.

‘Reasonable stabilisation path’ SCC

Stern argues that without a specific stabilisation goal, it is difficult to identify a reasonable monetary SCC. As mentioned above, the SCC is lower for a given level of abatement (through policy and/or technological progress). Stern estimates the policy induced price of emissions according to a ‘reasonable’ benchmark target, for example (in 2000 prices):

- a trajectory towards stabilisation of 550ppmCO₂e implies a SCC of $30/tCO₂e (£19);
- a trajectory towards stabilisation of 450ppmCO₂e implies a SCC of $25/tCO₂e; and
- an optimum goal for atmospheric concentration should be somewhere in this range.  

Stern then argues that the stabilisation level should be agreed according to estimates of what SCC will stimulate technological change. In this sense, Stern is estimating a SPC subject to the assumptions and uncertainties depicted in Figure 3. However, as explained in the introduction, this relies on all countries being committed to and adopting the same goal. A ‘UK-SPC’ associated with more than 550ppmCO₂e implies that not all other countries subscribe to this goal, so that the SPC and level of abatement in the UK will have to be higher than elsewhere. Not only would the total abatement cost in Britain be higher than elsewhere, it would be working towards an ‘inappropriate’ goal. If the target were set below 450ppmCO₂e, the converse applies.

Assumptions used to measure the SCC

One of best-know economic experts on the environment, William Nordhaus, has been sceptical of the assumptions used in the Stern Review’s swf.

- A single social planner whose preferences are displayed by a single swf (with uniform time preference and consumption elasticity) can only be a useful modelling approach in the base case, i.e. with no abatement measure. In assessing a policy approach (i.e. agreeing a stabilisation path) each country can only use the actual discount rates in local and regional capital markets.

- The logic behind a near zero discount rate reflect utilitarian philosophical traditions, ignoring alternative perspectives such as ‘each generation should leave as much social capital as it inherited’, or the Rawlsian idea that society should maximise the welfare

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23 The Review’s exchange rate is £100/tC (2000) = $116/tC (1995) = $35.7/tCO₂ (2000) so that £1=$1.31; this implies that $85/tCO₂ = £65/tCO₂ and $25/tCO₂ = £19/tCO₂

24 Nordhaus and Boyer (2000) estimate the SCC as $2.48/tCO2, which reflect a pure rate of time preference of 0.03 and the fact that they do not apply equity ratings as per the Stern review. They do not include such extreme costs arising from climate change and do not treat uncertainty in the same way.
of the poorest generation, i.e. today’s. A precautionary principle dictates that
societies maximise the minimum consumption in the riskiest scenario. More
fundamentally, no current generation can make decisions for (or bind the decisions
of) future generations.

- While it is reasonable to assume that individuals with the same consumption at a
given moment in time value that consumption equally, over time there are such
unimagined variations in technologies (etc.) that a certain inter-temporal preference
structure is likely to be flawed. The time discount rate and consumption elasticity
cannot be chosen independently in the growth (Ramsey) approach (since the real rate
of return has to equal the growth in consumption over time).

In short, the normative assumptions of the swf imply that saving today should be double
what it is today, reducing current consumption to improve the welfare of richer future
generations. While the approach to constructing a swf is common among estimates of the
SCC, the defining feature of Stern’s estimate is the choice of a near-zero discount rate.

*Green Book (Treasury)*

The Treasury ‘Green Book’ does not provide direct guidance on the SCC. However, it
advises that the discount rate to be used in public decision making ought to be 3.5%. Using
this in estimating a SCC or a SPC would result in much lower values than in the Stern
Review.

*Department for the environment and rural affairs (Defra)*

Defra has published widely around estimates of the SCC. A joint Defra-Treasury study by
the Government Economic Service (GES) estimated that the SCC, based on the global
damage of carbon emissions, was £19/tCO$_2$ and should rise by £0.27 annually in real terms.
Further research over time has moved over to the approach of estimating the SPC, and has
revised estimates upwards due to attempts to price uncertainty. Downing *et al* (2005)
concluded that £35/tC (£10.77/tCO$_2$) was a reasonable lower benchmark for global
decision, with modest aversion to extreme risks, low discount rates and low equity weighting.
However, the range of estimates is skewed such that the median is $4.31/tCO_2$.

Its latest advice in December 2007 argues that an SPC should be cautiously adopted based
on the range 450-550ppmCO$_2$e, in particular the upper end. Furthermore, it accepts the
estimation methods of the Stern review in stating that £19/tCO$_2$e should be the SPC,
uplifted in 2007 to £25 (or €40).

The Department’s view is that the SPC will increase over time, for the reasons already
mentioned, in line with that proposed by Stern. Furthermore, they argue that the SPC will
rise annually by the value of inflation (i.e. the GDP deflator). The PSC chosen should be
updated every five years to reflect reduced uncertainty over the scientific issues, reduced
uncertainty over abatement costs, and reflect improved coordination between governments.
McKinsey global MAC curves for 2030

Equivalent to the optimum stabilisation goal, McKinsey undertook a study to estimate the abatement costs necessary to attain a particular goal. Assuming a level of global agreement, the MAC estimates cover power generation, manufacturing industry, transportation, buildings, forestry, agriculture and waste disposal. Emissions targets of 400, 450 and 550ppmCO₂e are considered, all of which would require at least a 50% improvement in carbon efficiency relative to base projections. The marginal costs estimated (in 2007 prices) are:

- €40/tCO₂e to achieve 450ppmCO₂e.
- €25/tCO₂e to achieve 550ppmCO₂e.

These figures assume effective coordination of national governments and the veracity of policy. In the absence of these assumptions, the MAC must rise significantly. The equivalent of Defra’s calculation of the SPC in 2030 for this year is £40, possibly reflecting this.

EU Emissions Trading Scheme (ETS)

Carbon trading schemes is an indirect method to arrive at a shadow price of carbon, through a cap-and-trade approach. The gross emissions from heavy industries are given an upper limit and permits to emit greenhouse gases are distributed by national governments. This allows a marginal price to clear the secondary market, although considerable volatility was created by the different methods of distribution since Prices markets depend on the specific trading regime and risk management options. The forward price of carbon in August 2007 for December 2008 was €19/tCO₂ (£13), compared with forward prices in 2005 (during the first phase of the scheme) of €5-15/tCO₂. Given limited trading volumes, forward prices do not reflect future EU market prices.