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CAP148 - Deemed access rights to the GB transmission system for renewable generation

Document type: Impact assessment and consultation

Ref: 98/08

Date of publication: 16 July 2008

Deadline for response: 28 August 2008

Target audience: Transmission licensees, renewable and conventional generators, CUSC parties and any other party who has an interest in the transmission

Overview:

This document assesses the impact of proposals (CAP148 original and each of the five alternatives) to amend the Connection and Use of System Code (CUSC) to change the arrangements for certain classes of new generators (renewable or low carbon) to connect to and use the GB transmission system. CAP148 seeks to provide for priority connection for renewable and low carbon generation without requiring the completion of any transmission investment required to increase capacity. It also gives renewable and low carbon generation priority dispatch or firm access rights once connected.

Based on the findings of our impact assessment the Authority is minded to reject CAP148 because of the potential costs to customers associated with transmission constraints and the discriminatory nature of the proposal which does not appear to be objectively justified. This is a provisional view and is subject to further consideration of any points raised in response to this consultation process.

The Authority recognises that CAP148 could significantly reduce carbon emissions from the electricity sector and has quantified these potential benefits. But we think there are better ways of unlocking these benefits that are consistent with the existing legal framework and that would not expose customers to excessive constraint costs. These will be delivered through the Transmission Access Review.

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Context

There are a large number of mainly renewable generators waiting to connect to the GB transmission network, especially in Scotland. This situation, known as the “GB queue” arose following implementation of the British Electricity Trading and Transmission Arrangements (BETTA) which prompted an unprecedented volume of new applications for connection to the network and use of the transmission system. These applications were processed on the existing “first come, first served” basis under the current "invest then connect" approach to transmission investment and connection. Under this approach any project’s connection date and allocation of firm transmission access rights at a given Transmission Entry Capacity (TEC) is contingent on any identified transmission works being completed. The limited availability of transmission capacity on the existing transmission network, particularly in areas with the highest demand for that capacity, has lead to bottlenecks which are causing significant delays to projects’ connection dates.

CUSC Amendment Proposal CAP148 "Deemed access rights to the GB transmission system for renewable generation” proposes major changes to the current connection and access arrangements. CAP148 proposes prioritising the connection and dispatch of new renewable generation over all other generation including both conventional and existing renewable generation. There is a range of other initiatives that are also seeking to address issues relating to the GB queue and transmission access more generally. This includes a number of pending and recently approved CUSC amendment proposals, and the Transmission Access Review.

Associated Documents

CAP148 Amendment Proposal. May 2007.
CAP148 Working Group Report. September 2007.
CAP148 Final Amendment Report. December 2007.
CAP147 Amendment Proposal. February 2007.
http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/currentamendmentproposals/

CAP148 Initial Thoughts on Charging, October 2007.
http://www.nationalgrid.com/NR/rdonlyres/1D5ACF49-FEB3-4759-A0CC-8082A88126FD/20357/CAP148Charging_OpenLetter.pdf

Final Conclusions Report - GB Queue Management. July 2007.
http://www.nationalgrid.com/NR/rdonlyres/47B95865-0225-45C2-B3BE-F753821B1E1B/18039/FinalConclusionpaper.pdf

Short Term Access Governance Report – Report to the Secretary of State. October 2007.
http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/KSTAG_071008.pdf

Transmission Access Review - A Call for Evidence for a Review of Transmission Access. August 2007.
http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/070816_Ex_TAR%20Call%20for%20Evidence_FINAL.pdf

Transmission Access Review – Interim Report to the Secretary of State. January 2008.
http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/080131_TAR%20Interim%20Report_Consultation_FINAL.pdf

Transmission Access Review – Analytical Discussion Document. April 2008.
http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/080416%20TAR%20Access%20Discussion%20Document_FINAL.pdf

Transmission Access Review – Final Report to the Secretary of State. June 2008.
http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/080626_TAR%20Final%20Report_FINAL.pdf

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Summary

Background

Under the current rules, applications for connection to and use of the transmission network are processed on a “first come, first served” basis. The connection date for new generation and allocation of firm transmission access rights up to a Transmission Entry Capacity (TEC) is contingent on the completion of any necessary transmission works. Any contingent transmission works for a given project are identified on the basis that all other projects with signed agreements proceed to connection, and that all existing generators which are already connected continue to use the system.

The limited availability of transmission capacity on the existing transmission network, particularly in areas with the highest demand for that capacity such as Scotland, has meant that many projects require significant reinforcements to the network before they can connect. As a result, many projects have signed agreements for connection dates far into the future; transmission capacity which they might otherwise be able to use is already allocated to projects higher in the GB queue, leading to “bottlenecks”.

CAP148 - deemed access rights to the GB transmission system for renewable generation

CUSC Amendment Proposal CAP148 was raised by Wind Energy (Forse) Ltd in April 2007. The proposer highlighted the delays in gaining access to the transmission system under the current arrangements, and the problems caused by differences in the timing of transmission connection and the planning consent process and the duration of any planning consent. CAP148 seeks to address these issues by proposing major changes to the current arrangements. These changes would guarantee the connection and dispatch of new renewable generation over other generation technologies, including both conventional and existing renewable generation. The proposer of CAP148 considered that existing European legislation, in particular Article 7 of the Renewables Directive, allows Member States to provide priority access to the grid system to renewable generation, and that by utilising these provisions the proposal would better promote Government objectives for the growth of renewable generation and support the achievement of Government targets for carbon emissions reductions.

Prior to CAP148 being raised in February 2007 its proposer had submitted a similar proposal, CAP147, which the CUSC Panel recommended be withdrawn on the basis that it clearly worked against the CUSC objectives, and was not consistent with National Grid’s licence obligations. Ofgem intervened and explained that the issues raised by CAP147 should be assessed and considered under the CUSC, and clarified that the Authority is able to assess carbon savings as a relevant factor under the CUSC. We have subsequently issued guidance on the treatment of carbon costs in the codes governance framework.

Given the importance of the issues associated with CAP148, the Authority has decided to conduct an impact assessment.

Initial findings from our impact assessment

In our impact assessment, set out in chapter 3, we have considered the impacts of all of the variants of CAP148, including the original proposal and the five alternative amendments developed by the Working Group. To help us undertake this task, we have undertaken quantitative analysis of specific impacts of CAP148, in which we have looked at a full range of generation scenarios and taken account of a range of uncertainties. Our quantitative analysis shows that when incorporating the benefits of carbon abatement, whether using DEFRA's calculation of the Shadow Price of Carbon or using forecast EU ETS carbon prices, the additional operational costs outweigh the carbon savings in every scenario modelled. This is largely driven by the constraint costs associated with allowing significant volumes of new generation to connect before investments are made to increase the capacity of the transmission system. We have therefore reached a preliminary view that CAP148 would not lead to a net positive outcome for consumers under any scenario.

In addition, CAP148 explicitly discriminates in favour of renewable generators who would be eligible for Deemed Transmission Entry Capacity (DTEC) under the proposal. We have considered whether the differences in treatment between DTEC and non-DTEC generators could be considered due discrimination both in the context of relevant EU legislation and the Authority's statutory duties. We have reached the preliminary view that there is no objective justification for discrimination of the type envisaged by CAP148.

We would welcome respondents' views on our preliminary views on both these issues. Based on our assessment of the impact of CAP148 and our assessment of the relevant legislation and the Authorities legal duties, the Authority is currently minded to reject CAP148 including all the alternative proposals. This is our preliminary view only, and we invite respondents to this consultation to present their views on CAP148, together with any further evidence they would like the Authority to consider in reaching its final decision to show that the differential treatment proposed by CAP148 can be justified. We are open to respondents putting forward reasons and arguments challenging our analysis of the costs and benefits and such other of our views set out in this document to persuade us to move from our minded-to position.

Interaction with the Transmission Access Review

CAP148 is being considered at a time when the industry, Ofgem and the Government are developing proposals for a new regime for transmission access under the Transmission Access Review. Ofgem is working hard to ensure that access to the transmission system does not act as a barrier to renewable and other new generation. Our proposals for the reform of the access arrangement include a radical re-design of the existing arrangements, measures to provide appropriate incentives for the transmission operators to build new infrastructure, and short term measures to help minimise the current queue for connections.

Whilst we are minded to reject CAP148 including all of the alternatives, we consider that there are much better ways of unlocking the benefits, primarily lower carbon emissions, of allowing faster connection of renewables that CAP148 is seeking to achieve, without prioritising any particular technology. We consider that the Transmission Access Review will provide short and longer term solutions which will allow significant volumes of additional renewable generators timely connections to the network, which will not involve substantial cost increases to consumers, and that will be consistent with the current legal framework.

1. Introduction

Chapter Summary

This chapter sets out the background to this document and the legal framework against which we developed our impact assessment. It also sets out a summary of the chapter structure of this document.

Question box

There are no questions in this chapter.

Background to CAP148

1.1. There are a large number of generators awaiting connection to the GB transmission network, especially in Scotland. This situation, known as the “GB queue” arose following implementation of the British Electricity Trading and Transmission Arrangements (BETTA) which saw an unprecedented volume of new applications for connection to the network and use of the transmission system. Applications for firm transmission access rights up to a given Transmission Entry Capacity (TEC) were processed on the existing “first come, first served” basis under the "invest then connect" approach. Under these arrangements, any transmission works required for a given generation project are identified on the basis that all projects with signed agreements proceed to connection and that all existing generators which are already connected continue to use the system. The given project’s completion date is then contingent on the identified transmission works being completed, after which TEC is granted and the generator can start to use the transmission system.

1.2. The limited availability of transmission capacity on the existing transmission network, particularly in areas with the highest demand for that capacity such as Scotland, has meant that many projects require significant reinforcements to the network before they can connect. As a result, many projects have signed agreements for connection dates far into the future, as transmission capacity which they might otherwise be able to use is already allocated to projects already existing on the system or higher in the GB queue, leading to “bottlenecks”. These bottlenecks can cause significant delays to projects’ connection dates.

1.3. In the context of the GB queue, the "invest then connect" approach can result in significant delays for new generators seeking access to the transmission system, in some cases up to 10 years after their requested connection date. This has led to growing frustration within the wind generation developer community, as the lead time for grid access can significantly exceed the timescales to develop and build a windfarm, and may also be dependent on other projects in the GB queue.

1.4. CUSC Amendment Proposal CAP148 "Deemed access rights to the GB transmission system for renewable generation" was raised by Wind Energy (Forse) Ltd (“Wind Energy”) in April 2007. CAP148 seeks to address the above issues by proposing major changes to the current arrangements so as to prioritise the connection and dispatch of new renewable generation over generation from other technologies, including both conventional and existing renewable generation. Specifically, through the introduction of a new transmission access product, Deemed Transmission Entry Capacity (DTEC), applicable to new renewable generation. CAP148 seeks to guarantee connection to the system for such generation within a given lead time of achieving planning consent, as well as prioritising despatch of this generation once connected.

Legal and assessment framework for amendments to the CUSC

1.5. The CUSC sets out the standard commercial terms between generators (and other network users) and National Grid. The CUSC also sets out the set series of procedures which must be followed in relation to proposals to amend the CUSC. Anyone who is party to the CUSC can propose an amendment to the CUSC. Once a CUSC amendment proposal has been raised, the CUSC Panel assess it before referring it to the Authority for a decision. After receipt of the Final Amendment Report from the CUSC Panel, the Authority makes a decision as to whether or not to direct implementation of the Amendment Proposal or any of the alternatives.

1.6. Appendix 4 outlines the procedure for raising proposed amendments to the CUSC, including the development of alternative amendments by the Working Group. Appendix 4 also outlines the legal and assessment framework for our decision, including the requirement to undertake an impact assessment in certain circumstances.

1.7. The Working Group set up for CAP148 developed five Working Group Alternative Amendments (WGAAs); no further alternatives were raised during National Grid's consultation process. The CUSC Panel discussed CAP148 at its meeting of 30 November 2007 and unanimously recommended rejection of the original proposal and each the WGAAs. We received the final Amendment Report for CAP148 on 14 December 2007.

1.8. Having considered the Final Amendment Report in respect of CAP148, it is our view that this proposal (including the alternative proposals) is important for the purposes of Section 5A of the Utilities Act, specifically with respect to the potential impact on market participants and the environment. It is on this basis that the Authority has decided to publish this impact assessment.

1.9. This document contains the impact assessment we have carried out in respect of CAP148 and also sets out the Authority's minded-to position in respect of CAP148. In reaching its minded-to position, the Authority has followed the decision-making process described in Appendix 4. The Authority will follow the same decision-making process in making its final decision on the proposals, where it will take into account views of respondents to this consultation.

1.10. The Authority's minded-to position is a preliminary view only, and we invite respondents to this consultation to present their views on CAP148, together with any further evidence they would like the Authority to consider in reaching its final decision. As such, where in this document we refer to Ofgem's or the Authority's views, that is a reference to our preliminary views, and is subject to consideration of any points raised in response to this consultation process.

Environmental issues and code objectives

1.11. In setting out CAP148, the proposer Wind Energy considered that existing European legislation, in particular Article 7 of the Renewables Directive, allows Member States to provide priority access to the grid system to renewable generation, and that by utilising these provisions the proposal would better promote Government objectives for the growth of renewable generation and support the achievement of Government targets for carbon reductions.

1.12. Prior to CAP148 being raised, Wind Energy had submitted a similar proposal, CAP147, which was considered by the CUSC Panel at its meeting in February 2007. Having considered the proposal against the relevant criteria for taking the amendment forward, the CUSC Panel recommended that CAP147 be withdrawn as it did not consider that the matters being proposed by CAP147 could be considered within the remit of the CUSC governance arrangements, and were more of an issue for government.

1.13. National Grid in its role as chair of the CUSC Panel wrote to Wind Energy and Ofgem, copied to BERR, on 6 March 2007 to state that it did not consider that under any scenario the issues raised under CAP147 could be taken forward, and to seek our views on the issue. National Grid's view was that CAP147 clearly worked against the CUSC objectives, and was not consistent with National Grid's licence conditions on non-discrimination, and obligations to build, maintain and operate an efficient, economic and coordinated transmission system.

1.14. We considered the issues raised with respect to CAP147 and wrote back to the CUSC Panel on 17 April 2007 to clarify that the Authority's view with regards to discrimination was that the term requires (subject to what is said further below) not only that like situations be treated alike, but equally that non-equivalent situations may be required to be treated differently; this typically being referred to as "due discrimination". We also noted that no discrimination arises where like situations are treated differently provided that the difference in treatment can be objectively justified i.e. provided that the difference in treatment is pursuing a legitimate aim and is a proportionate means of achieving that aim. It should therefore be open to Wind Energy to argue either that certain forms of generation are not equivalent and so a difference in treatment need not necessarily be ruled out as "discriminatory", or (even where certain forms of generation are equivalent) that a difference in treatment is objectively justified.

1.15. In relation to the requirement to maintain an economic and efficient transmission system we noted that it would be possible to make an argument that it is more economic and efficient for generators that do not emit carbon to have grid access than for carbon emitting generators to have access. This may be justified in terms of the environmental costs associated with higher carbon emissions. We considered that the CUSC process should facilitate this debate and discussion.

1.16. Following our letter of 17 April 2007, we considered it would be helpful to issue further guidance to industry participants on the treatment of greenhouse gas emissions within the existing code objectives. On 30 June 2008 we published final guidance[1] on the treatment of carbon costs within the existing codes governance framework. Our guidance reflects and

[1] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=158&refer=Licensing/IndCodes/Governance

builds upon the principle stated in our 17 April 2007 letter and our preliminary assessment of CAP148 is consistent with this position.

1.17. In reaching its minded-to position on CAP148 the Authority has taken account of the potential carbon savings which may arise from CAP148. Those savings are relevant when assessing CAP148 against applicable CUSC objective (a), in terms of National Grid's licence obligation to develop and maintain an efficient, co-ordinated and economical system of electricity transmission. The Authority has also taken account of carbon savings in its preliminary assessment of CAP148 in terms of the Authority's wider duties, e.g. in relation to economy and efficiency, the environment and sustainable development, and the Authority's principle objective to protect the interests of current and future consumers.

Wider context for CAP148

1.18. We have considered CAP148 in its own right, within the legal framework described above including the consideration of carbon savings. However we also note that there is a wider context for the issues which CAP148 seeks to address, and other initiatives which are also seeking to address those issues.

1.19. A number of factors contributed to the creation of the GB queue. This includes the BETTA transitional arrangements and substantial financial incentives to connect renewables, such as the Renewable Obligation Certificate (ROC) mechanism, as well as government and EU targets. CAP148 is only one of a range of initiatives seeking to address issues in relation to the GB queue and transmission access more generally.

1.20. In relation to addressing the GB queue, on 1 May 2008, the Authority approved the CUSC amendment, CAP150 "Capacity Reduction". CAP150 was proposed by NGET and sought to facilitate the creation of gaps in the GB queue by providing a framework under which NGET could release transmission capacity which is unlikely to be required by a given project. This is part of a suite of initiatives being adopted by NGET, which includes greater information on project milestones and associated works, and a revised methodology for filling gaps in the queue created by projects terminating or having their capacity reduced.

1.21. In terms of the wider transmission access regime for generation projects, Ofgem and BERR published their final report to the Secretary of State on the Transmission Access Review (TAR) on 26 June 2008. This project was initiated after the publication of the Energy White Paper in May 2007 which requested Ofgem and BERR to review the present technical, commercial and regulatory framework for the delivery of new transmission infrastructure and the management of the grid. The motivation for the review was to ensure that the grid arrangements remain fit for purpose as the proportion of renewable generation on the system grows[2].

1.22. TAR relates to CAP148 in that it is intended to help remove the barriers to access to the transmission system that generators, including renewable and low carbon, are facing. The conclusions of TAR set out clear steps to remove these barriers and to create the appropriate regulatory and commercial framework and rules for the short and long term.

[2] For more information on TAR please visit the following link: http://www.ofgem.gov.uk/NETWORKS/TRANS/ELECTRANSPOLICY/TAR/Pages/Traccrw.aspx

We expect the TAR work programme to deliver short term and long term measures which will allow significantly more renewable and other low carbon generators to gain access to the transmission network much faster than under the current rules. One of the key conclusions made in the TAR final report is that the suite of changes that have been identified will address the problems associated with grid access without having to resort to prioritising any particular technology. This is important given the significant uncertainty about which technology or combination of technologies is likely to be the least expensive way to significantly reduce carbon emissions from the electricity sector.

Structure of this document

1.23. The remainder of this document is structured as follows:

- Chapter 2 provides an overview of CAP148, discusses the variations between the original amendment proposal and each of the alternatives, and outlines the key areas of impact.
- Chapter 3 sets out our assessment of the impacts of CAP148.
- Chapter 4 sets out the Authority's preliminary assessment of CAP148 against the legal framework for the purposes of reaching its minded-to position.
- Chapter 5 sets out conclusions and the way forward.

1.24. Section 5A of the Utilities Act 2000 requires that where an impact assessment is undertaken it must include an assessment of the likely effects on the environment of a proposal. Our assessment of environmental impacts is incorporated within the discussion of the impact on sustainable development in chapter 3.

2. Overview of CAP148 and key areas of impact

Chapter Summary

This chapter provides an overview of CAP148, discusses the variations between the original amendment proposal and each of the alternatives, and identifies the key areas of impact assessed in this document.

Question box

Question 1: Do respondents consider that we have appropriately identified the key elements of CAP148 and the key areas of impact?

Question 2: Are there any other factors that respondents would like us to consider, providing comments where possible on the impact of any factors raised?

Overview of CAP148

Original amendment proposal

2.1. The original amendment proposal seeks to introduce a new capacity product – Deemed Transmission Entry Capacity, or DTEC – applicable to eligible new renewable generation entering a Bilateral Connection Agreement (BCA) or Bilateral Embedded Generation Agreement (BEGA). DTEC guarantees connection by a firm date and ensures priority dispatch for these new renewable generators once connected. The priority connection element of the original amendment proposed that the firm date for connection is based on a lead time of 3 years after the later of (a) the date on which the user signs a relevant bilateral agreement with NGET or (b) the date on which the project obtains its project planning consent, unless Transmission Entry Capacity (TEC) can be allocated sooner.

2.2. The priority connection element of the original amendment requires that the transmission works identified as being necessary to connect the generator under the current arrangements be broken down into:

- **Directly Consequential Works (DCW)**: local works required to connect the generator to the electricity grid; and
- **Wider Works (WW)**: deep reinforcement works required to provide capacity to support the additional generation coming online.

2.3. The firm connection date is subject to completion of DCW and commissioning of the generator, but unlike allocation of TEC it is not contingent on completion of WW. This differentiation between DCW and WW underpins the proposed financial liability arrangements. In this respect, the original amendment proposal provides that NGET has relief from the risk exposure associated with delays linked to DCW caused by external events but does not have any relief for delays to the WW caused by external events.

2.4. The priority despatch element of the original amendment seeks to ensure that generators holding TEC would be constrained off prior to generators holding DTEC[3]. Administered Interruption Payments would apply to any DTEC or non-DTEC generators which are constrained off the system in the circumstance that the GB transmission system cannot accommodate both plant with TEC and plant with DTEC. The administered Interruption Payments would cover the “associated losses” associated with being constrained, i.e. foregone profits, including any foregone ROC payments in the case of renewable generators. The costs of the administered Interruption Payments would be recovered via Transmission Network Use of System (TNUoS) charges.

2.5. Under the original amendment the eligibility criteria for DTEC generation are based on eligibility for Renewable Energy Guarantees of Origin (REGO) under the Electricity (Guarantees of Origin of Electricity Produced from Renewable Sources) Regulations 2003. This includes generation provided by technologies that can only produce REGO eligible output, for example wind or hydro-generation, as well as technologies that can produce a proportion of output that qualifies for REGOs, for example, co-fired generation and mixed holding plants. Generators in the latter category are referred to as “proportionally qualifying plant”, with only the output produced from energy crops eligible for REGO certificates.

Alternative amendment proposals

2.6. During its consideration of CAP148, the Working Group found the original amendment proposal complex to develop in terms of the priority despatch element and the application to proportionally qualifying plant (defined above). The Working Group considered several possible candidates for alternative proposals, based upon variations on certain key principles contained within the original CAP 148 proposal.

2.7. None of the potential alternative proposals considered by the Working Group included the priority despatch element of the original proposal; instead they all allow for DTEC generation to receive constrained off payments through the Balancing Mechanism (BM). As such, under all of the alternative proposals, NGET would take constraint management actions on the basis of bids and offers submitted to the Balancing Mechanism (BM). In this respect, market forces would determine which generators should be constrained down or off the system in the event that such actions were necessary, with DTEC generators treated on the same basis as generators with TEC. The working group considered that in practice eligible generators would be likely to set bid prices which would make them least attractive to constrain down or off, resulting in the same outcomes as under priority dispatch.

2.8. Each of the potential alternative proposals considered by the Working Group retained the priority connection element of the Original amendment, albeit with some variations. In developing options for alternatives the Working Group considered a range of potential variations in terms of the eligibility of generation, the allocation of risk associated with delays and lead times for connection. For example, an alternative lead time of 4 years was proposed as being more reflective of the duration that transmission reinforcement takes to

[3] The Working Group also recognised that under National Grid’s licence obligations with regard to system security, in the event of constraints, balancing actions may need to be taken on plant with DTEC before all other feasible balancing actions have been exhausted.

complete, while a range of alternative eligibility criteria were considered in order to simplify the proposal by excluding proportionally-qualifying generation.

2.9. The specific options considered within each of these categories are outlined below and described in more detail in the CAP148 amendment report:

- **Eligibility:** The Working Group considered four main categories of eligibility in terms of whether particular forms of generation would be able to obtain priority grid connection under CAP148. These are set out at 1-4 below, although only options 3 and 4 were supported by the Working Group as forming the basis of an alternative amendment:

  1. **All REGO generation (as under CAP148 Original)**: under this option all generation that qualifies for REGOs would be eligible, including proportionally qualifying plant.

  2. **Intermittent REGO generation only, minus proportionally qualifying plant** - this differs from option 1 above in that only *intermittent* REGO generation (defined as generation technologies with a variable fuel source over which the generator has limited or no control) would be eligible for DTEC. This option excludes proportionally qualifying plant.

  3. **Low carbon generation, minus proportionally qualifying plant** - under this approach any form of generation identified as low carbon would be eligible for DTEC. The Working Group defined low carbon generation as plant which emitted no more than 0.2 tonnes of carbon per MWh generated.

  4. **All REGO generation, minus proportionally qualifying plant:** this differs from option 1 above in that it specifically excludes proportionally qualifying plant from being eligible for DTEC, as a pragmatic solution to avoiding the complexities associated with allocating DTEC for a proportion of a generator's output.

- **Risk allocation for delays**: The Working Group identified three potential options in terms of the allocation of risk associated with delays to completion of wider transmission works (WW) due to external events, as follows:

  A. Relief from external events (as now) - NGET has all current relief from external events that cause delays to WW.

  B. No relief for planning - Under this option, NGET has no relief from external events arising from delays in obtaining planning permissions for WW. However, NGET would be eligible for relief for delays caused by force majeure events, for example in the event of flood, famine, war or terrorism etc.

  C. No relief (as under CAP148 Original) - Under this option, NGET would have no relief from external events that cause delays to WW, however arising.

- **Lead time**: The Working Group identified two possible options in relation to the lead time for an eligible generator to obtain DTEC, subject to completion of DCW and commissioning of the generator, as follows:

X. 48 months - this provides a period of 48 months from the later of signing the relevant bilateral agreement or receiving planning approval for the station.

Y. 36 months (as under CAP148 Original) - this provides a period of 36 months from the later of signing the relevant bilateral agreement or receiving planning approval for the station.

2.10. Overall, based on consideration of the range of potential alternatives arising from the above options, not all of which were supported, five Working Group Alternative Amendments (WGAAs) were developed by the Working Group. No consultation alternatives were raised by respondents to the industry consultation.

Summary of CAP148 variants

2.11. The matrix of CAP148 variants developed by the Working Group is summarised in Table 1 below. In this document, any reference to CAP148 relates to all the CAP148 variants referred to in Table 1, including both the Original and each of the five WGAAs, unless otherwise stated.

2.12. Table 1 uses the labelling system developed by the Working Group for the WGAAs, where the first character represents the choice of eligibility criteria, the second the risk allocation and the third the choice of lead time. For example, WGAA 4BX is based on eligibility option 4 (All REGO generation minus proportionally qualifying plant), risk allocation option B (NGET does not receive relied for delays in obtaining planning permissions for wider works) and lead time option X (4 years).

Implementation issues

2.13. Any of the CAP148 variants, if implemented, would apply directly to all offers issued to eligible generation after the implementation date. Although the proposal would not apply retrospectively, eligible generators which already have a signed agreement but are not connected as of the CAP148 implementation date could switch to DTEC and the new provisions would apply from the date they sign an amended agreement (rather than the date of signing their current agreement). This means that the earliest any user could hold DTEC is three years after implementation of CAP148. New users could, however, still access the system earlier in the event that full TEC is made available prior to 3 years elapsing.

2.14. Implementation of any of the proposals would also require consequential changes[4] to other industry documents, including changes to the Transmission Charging Methodologies to reflect the introduction of DTEC. Given the magnitude of the potential changes and long lead time for connection of the first generation with DTEC if CAP148 is approved, NGET has indicated that it would only take forward those changes following the Authority decision. However, in parallel with the CAP148 process NGET published an open letter[5] to assist parties in understanding the potential consequences of the proposals on the Charging Methodologies.

[4] The consequential changes to other documents are discussed in more detail in the next chapter.
[5] Available on National Grid's website at http://www.nationalgrid.com/NR/rdonlyres/1D5ACF49-FEB3-4759-A0CC-8082A88126FD/20357/CAP148Charging_OpenLetter.pdf

Table 1: Matrix of CAP148 variants

		Priority	Connection	Priority Despatch
Variant	**Eligibility**	**Lead time**	**Risk Allocation**	**Included?**
Original	All REGO generation	3 years	Relief from external events causing delays to local works but no relief from external events causing delays to wider works	Yes
WGAA 3BX	Low carbon generation	4 years	No relief for planning	No
WGAA 4AX	All REGO generation minus proportionally qualifying	4 years	Relief from external events (as now)	No
WGAA 4BX	All REGO generation minus proportionally qualifying	4 years	No relief for planning	No
WGAA 4CX	All REGO generation minus proportionally qualifying	4 years	No relief	No
WGAA 4CY	All REGO generation minus proportionally qualifying	3 years	No relief	No

CUSC Panel recommendations

2.15. The CUSC Panel discussed CAP148 at its meeting of 30 November 2007 and unanimously recommended rejection of the original proposal and each of the WGAAs. We received the final Amendment Report for CAP148 on 14 December 2007. The recommended implementation date for each of the proposals, if approved by the Authority, is 10 Business Days after the Authority decision. The Amendment Report notes that this is based on the assumption that any consequential changes to the Grid Code, GB Security and Quality of Supply Standards (SQSS) and any other documents are completed before the first DTEC holder is physically connected.

Proposals considered in this impact assessment

2.16. The Working Group developed legal drafting for WGAA 4BX only, but noted that legal drafting for the other WGAAs could be created by amendment to that developed for WGAA 4BX. The Working Group agreed that no drafting would be developed for the CAP148 Original, although this proposal was not withdrawn and was voted upon by the CUSC Panel. The fact that the Working Group did not work up CAP148 Original in detail makes it difficult to assess the likely impacts of the priority despatch element or of the application to proportionally qualifying plant. However, this impact assessment considers the potential impacts of each of the CAP148 variants to the extent that this is possible based on the information available in the Amendment Report.

2.17. We note that in considering the potential impacts of CAP148 there is an interaction with the consequential changes to the Transmission Charging Methodologies. Such changes to the transmission charging methodologies are out of scope of the CUSC, but are relevant to our consideration of the potential wider impacts of the proposal. The analysis set out in this document is based on ***"socialisation"*** of the majority of the additional costs through Transmission Network Use of System (TNUoS) or Balancing Services Use of System (BSUoS) charges under the current Transmission Charging Methodologies. However, to illustrate the range of potential impacts we also consider the extent to which the impacts might change if the additional costs of CAP148 were allocated directly to DTEC generators through cost-reflective charges.

Overview of impacts

2.18. In considering the potential impacts of CAP148, we have first undertaken quantitative analysis of specific direct and indirect impacts of the features of the proposed modification and its alternatives. We have then applied this analysis in considering the overall impact of CAP148 according to the key themes which are relevant to the legal and assessment framework by which the Authority must consider CAP148. These impacts are outlined below and set out in chapter 3.

2.19. Under the **priority connection** element of CAP148, qualifying generators may be able to connect to the transmission system sooner than they would otherwise, as their connection date would no longer be contingent on the completion of wider works (WW), but would instead be based on a lead time associated with obtaining planning consents. This aspect of CAP148 would in turn be expected to have specific impacts in a number of areas, including:

- **Connected generation capacity:** Accelerating the connection of qualifying generation would change the connected plant mix for a given year.
- **Short term operation**: The qualifying generation accelerated by CAP148 would displace conventional generation in the merit order, leading to shorter term impacts. On the one hand, higher marginal cost plant would run less often, leading to a reduction in the average cost of generating electricity, with a corresponding reduction in wholesale electricity prices. On the other hand, with a significant proportion of the qualifying generation being intermittent, reserve requirements and associated reserve costs would be increased. However, more significantly, there would be an increase in the incidence, volume and associated costs of transmission constraints.
- **Environmental impacts**: Displacement of conventional plant by renewable plant would lead to a reduction in emissions of greenhouse gases and other pollutants. In addition, the increase in total production from renewable plant would have an impact on the ROC mechanism, both in terms of progress towards meeting the ROC target and the likely level of ROC price, with an associated impact on the total ROC payments and potentially, the cost to customers of the ROC scheme.
- **Transmission investment**: The accelerated connection of qualifying generators would require earlier completion, and as a consequence earlier spend, on directly consequential works (DCW), leading to higher associated present value costs, while the progress of wider works (WW) would be unaffected.

- **Implementation costs**: CAP148 has associated implementation and ongoing costs, and requires consequential changes to other documents, with such development work leading to further costs and complexity. This includes changes to the transmission charging methodology to apply appropriate charges to parties holding DTEC rather than TEC. This may be more complex for variants for which the eligibility criteria include proportionally qualifying plant.

2.20. Inclusion of the **priority despatch** element of CAP148 original is likely to modify the impacts associated with the priority connection element of CAP148. While it would not be expected to impact on the connected capacity or transmission investment it may potentially affect competition and short term operation[6], which could in turn modify the impact on emissions and on the ROC mechanism. The priority despatch element of CAP148 may also require additional implementation costs and further consequential changes to industry codes and other documents, resulting in further complexity. This includes the development of a methodology for deriving the administered Interruption Payments and changes to the transmission charging methodology in order to charge out the costs of those payments.

2.21. Overall, taking the above specific impacts into account, CAP148 may be expected to lead to impacts in areas which are relevant to the legal and assessment framework by which the Authority must consider CAP148, as discussed in chapter 1 and set out in Appendix 4. This includes, among other things:

- **Consumers**: the impacts of CAP148, when taken together, would in turn be expected to lead to an impact on both current and future consumers, e.g. through the impact on electricity bills and social and environmental benefits through carbon savings; CAP148 may result in savings in carbon emissions. However, CAP148 might also impact on the efficiency of transmission system investment and operation, and therefore on the total cost of supplying electricity demand. Any associated costs which are not targeted back to parties who cause them would be met by customers.

- **Competition:** the accelerated connection of qualifying generation may have an overall impact on the level of competition in the electricity generation sector, while the differential treatment for those types of generation may have an impact on the ability of generators to compete on a level playing field.

- **Sustainable development**: CAP148 may impact on the five sustainable development themes that set out how Ofgem will contribute to the sustainability agenda[7], in particular in relation to managing the transition to a low carbon economy.

- **Discrimination issues**: it is important to consider the question of whether the difference in treatment between eligible generators and other users constitutes due discrimination, when considered in the context of the Authority's decision-making framework and taking into account wider legislative requirements such as particular provisions of the Renewables Directive.

[6] We consider the potential impacts of the priority despatch element in more detail in chapter 3.
[7] See Ofgem's second annual Sustainable Development Report, November 2007.

3. Quantitative and qualitative analysis of impacts of CAP148

Chapter Summary

This chapter sets out and seeks views on our assessment of the impacts of CAP148. It includes our quantitative analysis of specific impacts of CAP148, and considers the extent to which these impacts may differ between the different CAP148 variants. It also incorporates an assessment of environmental impacts as required under Section 5(2) of the Utilities Act 2000. We have also considered CAP148 in terms of key themes which are relevant to the Applicable CUSC objectives and the Authority's wider duties, including the Authority's principle objective and relevant European legislation.

Question box

Question 1: Do respondents consider we have appropriately identified, and where possible quantified, the impacts of CAP148, including environmental impacts? If not, what additional quantification is required?

Question 2: Do respondents consider that we have appropriately considered the extent to which these impacts may differ between the different CAP148 variants? If not, what further work is required?

Question 3: Do respondents consider that there are additional impacts that have not been fully addressed? Where respondents consider that there are additional impacts, what are these impacts?

Question 4: Do respondents wish to present any additional analysis that they consider would be relevant to assessing the direct and indirect impacts of the proposals?

Question 5: Do respondents have any views on the implementation issues associated with CAP148, including the nature, scope and development timescales for consequential changes to other documents?

Question 6: Do respondents have any views on the appropriate treatment of DTEC generators within the transmission charging methodology, or on the extent to which the impacts of CAP148 might be expected to vary depending on whether the additional transmission costs associated with CAP148 are socialised across all users or allocated to DTEC generators through cost-reflective charges?

Question 7: Do respondents wish to present any alternative arguments on legal grounds in relation to the discrimination issues arising under CAP148?

Question 8: Do respondents consider there are any further risks and unintended consequences associated with CAP148 which the Authority should consider in reaching its final decisions?

Introduction

3.1. This chapter sets out and seeks views on Ofgem's assessment of the impacts of CAP148 according to the following key themes:

- Impact on consumers
- Impact on competition
- Impacts on sustainable development
- Impacts on health and safety
- Risks and unintended consequences
- Other impacts including implementation costs.

3.2. In undertaking this impact assessment we have taken account of the work undertaken by the CAP148 Working Group in developing and assessing the original and alternative amendments[8]. We have also taken account of further information from National Grid[9]. We have also taken account of further analysis, set out in the next section, which we have undertaken in order to seek to quantify potential specific impacts of the priority connection element of CAP148. In the subsequent sections we apply this analysis in Ofgem's assessment of the impacts set out above.

Quantitative analysis of impact of priority connection[10]

3.3. Our quantitative analysis, on which we also seek views, is set out in this section, while Appendix 2 provides more details on the input assumptions and modelling methodology. Within this quantitative analysis[11] we have addressed a number of uncertainties through scenario-based modelling and sensitivity analysis. We have also considered the extent to which the quantified impacts may be expected to differ between the different CAP148 variants and modified by the inclusion of the priority dispatch element of CAP148 Original.

Connected generation capacity

Broad approach

3.4. We have derived a profile of connected generation capacity with and without CAP148, by considering the impact of the priority connection element on a project by project basis. To do so we have established a baseline scenario of renewable generation projects that will

[8] This includes illustrative calculations of the impact of CAP148 on constraints costs, provided by National Grid, set out in Annex 11 of the CAP148 Working Group Report.

[9] Information provided to Ofgem in response to a formal request pursuant to Standard Licence Condition B4 of National Grid Electricity Transmission's electricity transmission licence.

[10] We have had assistance from The Brattle Group ("Brattle") which has undertaken the modelling under Ofgem supervision using its own software and independently sourced data. Brattle has also had access to parts of the additional information provided by National Grid, subject to a confidentiality agreement. Within this section and appendix 3 any references to "we" and "our" include references to Brattle unless otherwise stated.

[11] We have assumed implementation of CAP148 on 1 January 2009 and presented all results in calendar years and all monetary data in nominal prices assuming 2% inflation. All present value (PV) data is reported in 2008 money.

come online in the absence of CAP148 out to 2020 (the “counterfactual”) and then examined how CAP148 might accelerate the connection of a given project within that baseline. Our modelling assumes that CAP148 would not in itself lead to an increase in the ultimate capacity of renewable generation in GB.

Base Case assumptions

3.5. Our Base Case counterfactual is based on a generation background and network model derived from data in the Seven Year Statement (SYS)[12] and TEC register[13]. We have also applied assumptions as to plant closures and further plant additions over the modelling horizon, together with transmission investment beyond the current SYS timescales. In considering the scope for acceleration of eligible generation, we have made further modelling assumptions as to the time period between planning consent being granted and a project being commissioned, and as to the date on which planning consent will be granted for individual projects based on their status in the TEC register. These assumptions have the effect that under the Base Case scenario all projects in the TEC register achieve planning consent and ultimately connect.

Generation background scenarios

3.6. There are a number of uncertainties surrounding the amount of connected generation capacity, both with and without CAP148, including:

- the degree to which the proposal will accelerate the connection of eligible generation,
- whether currently planned projects will materialise, and
- whether more projects will ultimately be realised than currently planned.

3.7. As a result of these uncertainties the approach used for the Base Case scenario may either overestimate or underestimate the generation capacity accelerated under CAP148. On the one hand, the Base Case scenario assumes that all projects in the TEC register ultimately connect. It does not take account of the risk of currently planned projects dropping out or other factors constraining construction of projects such as availability of the required component parts for wind turbines or of construction contractors. On the other hand, it is possible that the ultimate amount of new renewable capacity will be higher than that currently in the TEC register. The government has a target to source 15% of final energy consumption from renewable sources by 2020. Achieving this target could require between 35% and 40%[14] of electricity to be generated from renewable sources by 2020, compared to 33% in that year under the base case counterfactual scenario.

[12] We have used National Grid’s 2007 Seven Year Statement including the four quarterly updates.
[13] The TEC register contains the contracted TEC position for existing generators and for generators with signed bilateral agreements for future TEC, and is available on National Grid’s website. We have used the latest version as of 14 January 2008.
[14] See Renewable Energy Strategy Consultation, BERR, June 2008 at http://renewableconsultation.berr.gov.uk/consultation/consultation_summary, also the Transmission Access Review Final Report, Ofgem/BERR, June 2008 at http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/080626_TAR%20Final%20Report_FINAL.pdf

3.8. We have addressed these uncertainties by considering the following scenarios as to the level of renewable generation and of the proportion which is accelerated by CAP148[15]:

- **Base Case** – counterfactual includes all projects in the TEC register; under CAP148 it is assumed all projects that could accelerate do so (as described above)
- **High Case** – counterfactual assumes 38% of electricity to be generated by renewable sources by 2020, representing a "stretch target" modelled by increasing renewable generation capacity in each zone of the Base Case in proportion to the TEC capacity in that zone; under CAP148 it is assumed that all projects that could accelerate do so
- **Low Case** – counterfactual assumes a 50% dropout rate of projects in the TEC register, modelled by 50% less new renewable generation than in the Base Case; in addition it is assumed that only 50% of the volume of eligible generation in the counterfactual is able to accelerate under CAP148.

CAP148 variants modelled

3.9. As noted in chapter 2, in terms of the priority connection element of CAP148 the six variants (including the Original and the five WGAAs) are distinguished from each other by the option chosen under the three categories of variation, namely the eligibility of generation, the allocation of risk associated with delays and the lead time for connection. We have considered the potential impact of varying the choice of option in each of these categories, in order to determine the extent of quantitative modelling required.

3.10. All our modelling is based on eligibility criterion "4", i.e. all REGO generation minus proportionally qualifying. However in practice, for the projects in the TEC register, the variations on eligibility result in the same pool of generators able to accelerate under the priority connection element", with nearly all of the capacity eligible for, and able to benefit from, DTEC being onshore or offshore wind. Our quantitative modelling does not consider the impact of delays in WW on the basis that the probability of delays is highly uncertain and their inclusion could distort the analysis. Our analysis assumes that CAP148 is implemented on 1 January 2009. The earliest any project could hold DTEC is driven by the lead time applicable to the given CAP148 variant. For a four year lead time (option "X"), the earliest any given project could hold DTEC is 2013, being four years after the modelled implementation date. Under the three year lead time (option "Y") the earliest any given project can hold DTEC is 2012.

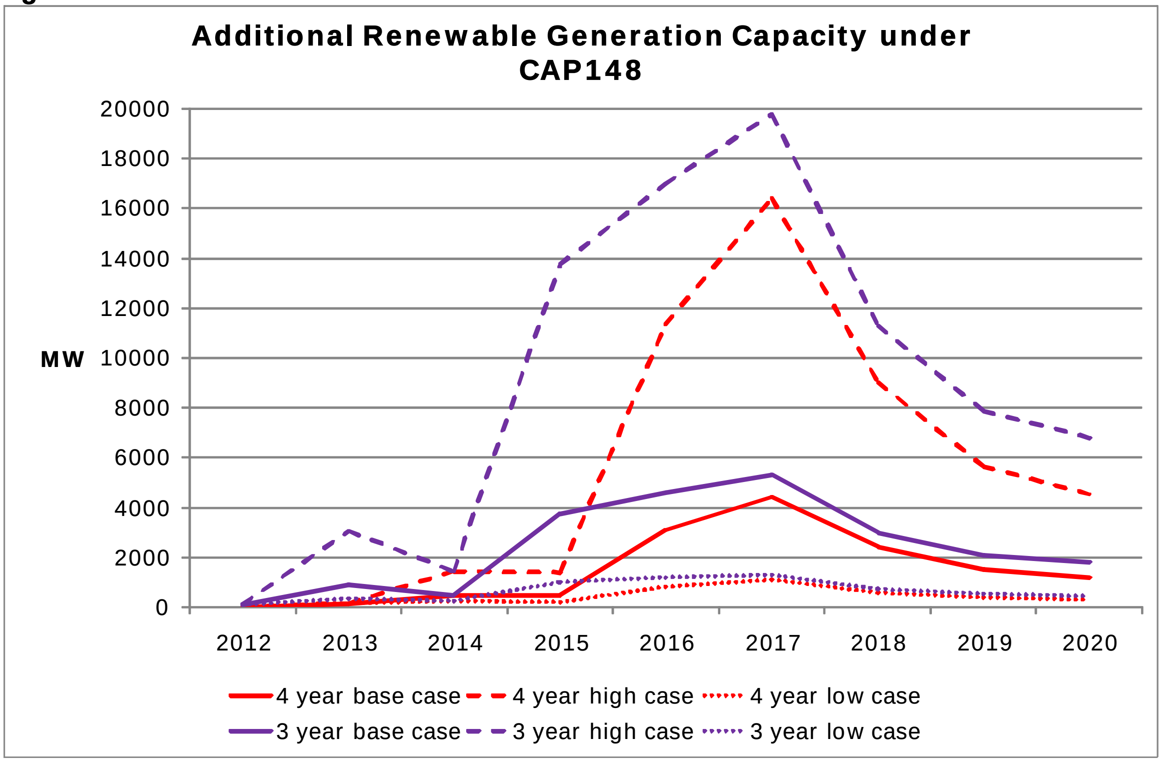
3.11. We consider that the only design feature to make a material difference to the quantitative analysis of the impact of CAP148 on connected generation capacity is the lead time for allocation of DTEC. We have therefore undertaken quantitative modelling under a range of scenarios for lead times of both three and four years, in order to represent WGAA 4CY and WGAA 4BX respectively. The relevance of our quantitative analysis to the other CAP148 variants is discussed below.

Impact on connected generation capacity

[15] There is also uncertainty regarding the impact of CAP148 on constraints costs. We have addressed this through further scenario modelling and sensitivity analysis, discussed below.

3.12. We have undertaken quantitative modelling of each of the three generation background scenarios described above, considering the impact of CAP148 both for a three year lead time and a four year lead time. The impact of CAP148 on the generation capacity profile for each year of each scenario is shown in Figure 1 below. Compared to the Base Case scenario, the volume of accelerated capacity is higher for the High Case scenario, and lower for the Low Case scenario. The results for a three year lead time are similar to those for a four year lead time, but the reduced lead time means there is more scope for CAP148 to enable plant to accelerate, and any accelerated capacity is online sooner. Figure 1 also shows a sharp increase in new renewable generation in 2016 for the 4 year lead time and 2015 for the 3 year lead time. This is a consequence of the assumptions used for determining the date on which a given project will receive planning consent and the limitations on those projects being able to connect earlier under CAP148.

Figure 1



3.13. Taken together, these six scenarios give a broad range of potential impacts of CAP148 on the connected renewable generation capacity. However, for the purposes of quantifying other areas of impact in the remainder of this chapter, we focus on the following scenarios which demonstrate the widest range of potential impacts, based on decreasing magnitude of impact on connected renewable generation capacity: **3 year, high case; 3 year, base case; 4 year, base case; 4 year, low case**.

3.14. Table 2 below shows the capacity of additional renewable generation under each year of these four scenarios. In each year the additional capacity reaches a peak value in 2017. For the 4 year Base Case scenario this peak value is just under 4400MW. The breakdown of additional capacity by renewable technology for the 4 year Base Case scenario is shown in Table A.5 of Appendix 2.

Table 2: Increased renewable capacity under CAP148

Increased renewable capacity (MW)		2012	2013	2014	2015	2016	2017	2018	2019	2020
4 year	**Base case**	**0**	**144**	**488**	**462**	**3081**	**4391**	**2400**	**1500**	**1200**
	Low case	*0*	*144*	*224*	*208*	*802*	*1080*	*579*	*362*	*289*
3 year	**Base case**	**94**	**910**	**488**	**3758**	**4581**	**5291**	**3000**	**2100**	**1800**
	High case	*94*	*3015*	*1442*	*13745*	*16961*	*19761*	*11250*	*7875*	*6750*

Impact on transmission investment costs

3.15. The accelerated connection of eligible generation under CAP148 would require acceleration of the DCW associated with those projects. This creates a present value cost associated with incurring the capital cost of those DCW sooner than would be the case otherwise. Our quantitative analysis assumes that these costs would be met by the relevant DTEC generator. Our analysis also assumes that the investment schedule and costs for WW would be unchanged, that is such works would be completed in the same timescales with and without CAP148.

Impact on reserve costs

3.16. With a significant proportion of the qualifying generation being intermittent, reserve requirements and associated reserve costs would be increased. In assessing these impacts we have used National Grid's estimates[16] for the potential costs for reserve of additional wind generation at £4m-£10m per year of reserve costs per additional GW of wind generation. We have applied the estimates at the lower end of this range to the generation capacity scenarios highlighted above, i.e. assuming an additional reserve cost of £4m/year for each additional GW of wind generation capacity.

Short term operation

Broad approach

3.17. We have used a merit order model to model short term operation under each generation background described above. Taking into account assumptions as to plant availability and marginal costs, the merit order model first calculates the unconstrained outputs of each plant by considering the cheapest way of meeting a given level of demand. The modelling then adjusts this pattern of generation to take account of transmission constraints. We assume constraints costs are based on plants' costs and, where applicable, the price of Renewable Obligation Certificates (ROCs). We have not explicitly modelled the priority dispatch element of CAP148 Original. In this subsection we analyse the impact of CAP148 by comparing the results with those for the given counterfactual in each year. We consider these impacts in PV terms below in the section in Impact on Consumers.

Impact on wholesale electricity prices

[16] Based on information supplied by National Grid.

3.18. In modelling unconstrained generation outputs we have assumed low marginal costs for hydro, onshore and offshore wind plants. Therefore additional wind and/or hydro plant reduce the outputs of conventional generation. As a result, plants with higher marginal costs would run less often and the average cost of generating electricity would be reduced, with a corresponding reduction in wholesale electricity prices. Table A.6 of Appendix 2 sets out the reduction in electricity prices which may be expected to result from CAP148 under the four scenarios highlighted above. Years with a higher volume of accelerated renewable generation capacity (mainly wind) have a lower cost marginal plant on average and lead to a greater reduction in wholesale electricity prices. For the 4 year Base Case scenario the greatest reduction in wholesale electricity price is in 2017, at approximately £0.7/MWh.

Impact on constraints costs

3.19. The accelerated connection of DTEC generation also results in an increased probability of generation being constrained off as the system would not be sufficiently reinforced until the WW are completed. This leads to an increase in the incidence, volume and associated cost of transmission constraints, compared to the counterfactual case.

3.20. For each scenario studied, we have modelled boundary constraints using a simplified zonal flow analysis based on study zones and associated boundary limits defined in the Seven Year Statement (SYS)[17]. In this analysis we have assumed that in the unconstrained schedule the transmission system is balanced in energy terms, so that the volume of generation constrained off matches the volume of generation constrained on, and that bid and offer prices reflect marginal costs and ROC prices. We calculate constraints costs as the *net* payment, i.e. constrained on payments minus constrained off payments.

3.21. Tables A.7 and A.8 of Appendix 2 show the impact of CAP148 on the volume and cost of constraints under the four generation background scenarios identified above. As might be expected, the results show that the impact of CAP148 on constraints volumes and costs is related to the volume of accelerated generation capacity. For the 4 year Base Case the greatest impact in a given year is in 2017 in which the increases are 16TWh for constraint volumes and £716m for constraints costs.

Additional scenarios and sensitivities

3.22. For a given generation background, there are a number of uncertainties surrounding the impact of CAP148 on the volume and associated cost of constraints. Noting that short term operation and in turn constraint payments are likely to be sensitive to fuel prices, we have modelled the following additional scenario which provides an alternative estimate of the impact of CAP148 under the 4 year Base Case generation background scenario:

- **High coal price** – all assumptions are identical to 4 year Base Case with the exception of the coal prices used (which are 50% higher than in the Base Case), with the effect that coal plant is marginal more often and renewable generation displaces more coal generation and less gas-fired generation than in the Base Case scenario, i.e. the same generation background but different operational outcomes.

[17] We have used National Grid’s 2007 Seven Year Statement including the 4 quarterly updates.

3.23. The results for this scenario are also included in Table A.7 and A.8 of Appendix 2, showing the High Coal Price scenario has similar constraints costs and volumes to the 4 year Base Case scenario, while Table A.6 of Appendix 2 shows it also has a similar impact on wholesale electricity prices. The respective environmental impacts are discussed below.

3.24. We have also compared our estimates of constraints costs with the illustrative calculations set out in the CAP148 Working Group report, taking into account further information from National Grid as to the basis of its analysis. As described in more detail in Appendix 2, we note that National Grid's estimates are lower than ours and we attribute this to the fact that National Grid's estimates were based on a simple modelling approach which considers only the most important constraint boundary and does not include costs of constraining off renewable plants. We have found that making reasonable adjustments to National Grid's model yields similar constraints costs to ours, and we conclude that our constraints costs estimates are reasonably robust. However, in order to provide an alternative estimate of constraints costs we have undertaken sensitivity analysis where we have used National Grid's estimate of constraints costs for non-renewable plants in place of our estimates for the 4 year Base Case scenario. This is discussed in the section on Impact on Consumers.

3.25. We also note that the increased incidence of constraints under CAP148 may also lead to an increased risk of anti-competitive behaviour by generators in a unique position to relieve those constraints. We consider the potential impact of such behaviour below through further sensitivity analysis, discussed in the section on Impact on Competition.

Impact on imbalance

3.26. The Balancing Mechanism seeks to ensure that actions taken to manage constraints are identified ("tagged out") and excluded in the calculation of imbalance prices so that they do not contribute to imbalance costs, although as described by Ofgem in the context of the cash-out review[18], this can sometimes be difficult to achieve in practice. If constraint actions are not correctly "tagged out" then any change in the net volume of actions required to manage constraints could potentially affect energy imbalance prices. However our analysis ignores this effect by assuming a balanced system, so that the volume of plant constrained off is the same as the volume of plant constrained on. Our analysis therefore assumes that CAP148 has no effect on imbalance volumes or imbalance prices. This may lead to an under-estimate of the full impact of constraint costs.

Environment

3.27. The changes in generation output discussed above would in turn have positive environmental impacts, as displacement of conventional plant by renewable plant would lead to an associated impact on emissions of greenhouse gases and other pollutants. In addition, the increase in total production from renewable plant would have an impact on the ROC mechanism, both in terms of the ROC target and the ROC price, with an associated impact on the total ROC payments. These impacts are quantified below for each year of each scenario and discussed in more detail in the section on Sustainable Development.

[18] Documents available at http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/CashoutRev/Pages/CashoutRev.aspx

Emissions savings

3.28. Tables A.9, A.10 and A.11 of Appendix 2 show the changes in output from renewable, coal and gas plant respectively, while Tables A.12 and A.13 show the corresponding volume of CO_2 and CO_2e savings[19] associated with the reduction in emissions as conventional plant is displaced by renewable generation, for each of the scenarios referred to above. We have calculated the value of the CO_2e savings in Table A.14, using the shadow price of carbon, as advised by DEFRA[20]. These tables show that the volume, and associated value, of emissions savings is higher for scenarios with a higher increase in output from renewable generation. For the 4 year Base Case the highest savings in a given year are in 2017 (4.1Mt CO_2e, valued at £157m), in which the renewable output is 10TWh higher under CAP148. Compared to the 4 year Base Case scenario the High Coal Price scenario has higher carbon savings (peaking at 6.9Mt CO_2e in 2017, valued at £261m) as the increased renewable generation displaces more coal plant and less gas plant.

3.29. Table A.15 provides alternative estimates of the carbon abatement value by valuing the CO_2 emissions savings (removing the effect of NOx[21] from the calculation) at the forecast EU ETS price. For the 4 year Base Case the highest savings in a given year are in 2017 (4Mt CO_2, valued at £72m using the EU ETS forecast price), in which the renewable output is 10TWh under CAP148. The High Coal Price scenario again yields higher carbon savings (peaking at 5Mt CO_2 in 2017, valued at £121m) than the 4 year Base Case scenario.

Effect on the ROC price and renewables targets

3.30. Taking into account our estimates of the impact on generation outputs, we have modelled the effect of CAP148 on the number of ROCs issued, and the associated impact this would have on the process of ROCs. Given the minimum lead time of 3 years for allocation of DTEC following implementation of CAP148, our modelling assumes a revised version of the RO scheme will be implemented in 2009. Our assumed RO scheme is based on the proposals set out by BERR in May 2007[22]. We have assumed the revised ROC scheme will include “banding” of renewable energy sources where some forms of renewable energy receive more or less than one ROC for each MWh of electricity produced. Under the revised mechanism the target level for the RO (expressed as a percentage of total electricity sales) takes account of the need for a minimum “headroom” between the RO target and the expected ROC production in order to prevent the ROC price collapsing. Because of the headroom in the revised ROC mechanism, the ROC “pot” is not fixed and the RO target and ROC payments will increase as the ROC production increases. When the headroom mechanism kicks in it effectively sets a floor which determines a minimum ROC price. Our analysis is based on a 6% headroom, resulting in a minimum RO Target of 106% of the expected level of ROC production, and a minimum ROC price of 106% of the ROC buyout price[23].

[19] The analysis also takes into account savings of other greenhouse gases, based on their carbon equivalent value.
[20] DEFRA, The social cost of carbon and the shadow price of carbon: what they are, and how to use them in economic appraisal in the UK, December 2007
[21] We have excluded NOx as do not think it is robust to value this at a traded price for carbon.
[22] BERR, Reform of the Renewables Obligation, May 2007.
[23] We have assumed a ROC buyout price of £35.76/MWh in 2008, increasing by inflation thereafter.

3.31. We cannot estimate directly the level of ROC production in our modelling as it only includes projects in the TEC Register and does not make assumptions of the growth of small scale renewables. However, we have estimated total ROC production and corresponding ROC price in each year in the absence of CAP148 using forecasts of RO-qualifying energy production made by Oxera[24] in a report commissioned by BERR[25] and our assumptions as to the banding[26] under the revised RO scheme. We estimate that the level of ROC production is high enough for the headroom mechanism to kick in from 2011 onwards, such that the ROC price is no longer set by the level of ROC production but by the floor price derived from the ROC buyout price and minimum headroom. We also found that the level of qualifying generation in the TEC Register, on which our modelled scenarios are based, exceeds Oxera's forecasts by over 50%. We conclude that each of our modelled scenarios (including the counterfactuals) have a total level of ROC production at least as high as that derived from Oxera's forecasts, such that the ROC price will be set by the floor price in each year of our modelling horizon, both with and without CAP148.

3.32. We have used our modelling results to estimate the change in ROC production under CAP148, and in turn the change in the ROC payments by applying the ROC price to the change in ROC production. These results are shown in Tables A.16 and A.17 of Appendix 2. For the 4 year Base Case scenario, the results for the year 2017 show an increase in ROC production of 11TWh and the increase in ROC payments of £496m.

Transmission charging

3.33. Each CAP148 variant would require consequential changes to National Grid's Use of System Charging Methodology. This would include changes to apply appropriate charges to parties with DTEC and to recover additional transmission costs through TNUoS charges or BSUoS charges as appropriate. Those changes may potentially affect non-DTEC users, and in turn consumers, to the extent that the additional transmission system investment and operational costs of CAP148 described above are socialised through the residual element of TNUoS charges or through non-locational BSUoS charges rather than targeted to holders of DTEC through cost-reflective charges.

3.34. Our quantitative analysis incorporates the following assumptions as to the impact of CAP148 on transmission charges:

- The costs of DCW are borne by the relevant DTEC generator and the transmission investment costs associated with the accelerated connection of DTEC generation has no impact on either the level of TNUoS charges or locational differentials.
- Additional reserve costs are recovered through BSUoS charges
- For the WGAAs, constraints costs are determined via the current constraint management system (i.e. the balancing mechanism) and are recovered through BSUoS charges
- For CAP148 Original, the costs of administered Interruption Payments are recovered through TNUoS charges. Our quantitative analysis assumes that this leads to the same overall level of constraints costs as the WGAAs.

[24] Available at http://www.berr.gov.uk/files/file39039.pdf.
[25] BERR based its impact assessment of the reformed RO on Oxera's forecasts.
[26] We assume offshore wind receives 1.5MWh of ROCs for every 1MWh produced, and for other forms of renewable generation the volume of ROCs allocated is equal to the volume of energy produced.

3.35. We note that the impacts of CAP148 may change under different charging assumptions as this may affect the acceleration rate and the proportion of additional costs which are ultimately met by consumers. This issue is considered in more detail below.

Implementation costs and consequential changes

3.36. As part of the industry assessment of CAP148, the potential impacts on industry computer systems and need for consequential changes to core and other industry documents were noted. As these impacts were not quantified as part of the industry assessment of CAP148 they are excluded from our quantitative analysis, but they are discussed in qualitative terms below in the section on Other Impacts.

Relevance of quantitative analysis to other CAP148 variants

3.37. As noted above, our quantitative analysis for lead times of three and four years represent WGAA 4CY and WGAA 4BX respectively. In preparing this impact assessment we have also considered the extent to which those impacts may be expected to change under different CAP148 variants. We welcome respondents' views on these matters and on the relevance of the quantitative analysis to each CAP148 variant.

Priority despatch

3.38. As noted above, the fact that the Working Group did not work up CAP148 Original in detail makes it difficult to assess the likely impacts of the priority despatch element. Based on the information set out in the Amendment Report, we have concluded that in practice the use of priority despatch is unlikely to have a material impact on how often a DTEC plant is constrained off compared to the other CAP148 variants, nor will it have a material impact on constraints costs. We have based this view on the assumption, consistent with the views of the Working Group, that under the existing market-based constraint management mechanism plants eligible for DTEC are likely to be among the last to be constrained off in any case. We consider that the bid prices submitted by DTEC generators in the Balancing Mechanism are likely to reflect not only their (generally low) marginal costs of production but also any ROC payments foregone by not generating. Conventional generators are likely to be constrained off first, and renewable generators last, even without the priority dispatch element of CAP148 Original.

Variations on eligibility criteria, risk allocation for delays, and lead time

3.39. As set out above in the section on "CAP148 variants modelled", we consider that the only variation on the design of CAP148 that is likely to make a material difference to the impacts in practice is the lead time. In terms of eligibility criteria, we note that based on the projects in the TEC register the different options result in practice in the same pool of eligible generators. We would note that the different options for risk allocation for delays are difficult to model, but that they are unlikely to have a significant effect on the impacts of CAP148 given the rarity of the relevant events leading to delays. We have considered the sensitivity of the impacts to the choice of lead time by modelling scenarios for both a three year and a four year lead time.

Conclusions

3.40. We conclude that the quantitative impacts of CAP148 on generation outputs and transmission costs may therefore be expected to be broadly the same with and without inclusion of the priority dispatch element, and between variants based on the same lead time, irrespective of any wider implications of those differences. That is, quantitative analysis undertaken for WGAA 4BX is also applicable to the CAP148 variants with a four year lead time (WGAA 3BX, WGAA 4AX and WGAA 4CX) while that undertaken for WGAA 4CY is also applicable to CAP148 Original.

3.41. The remainder of this chapter takes our quantitative analysis into account in setting out Ofgem's assessment of the impacts of CAP148 in the context of the key themes relevant to the legal and assessment framework against which we must consider CAP148.

Impact on consumers

3.42. The impacts of CAP148 quantified above, when taken together, would in turn be expected to lead to an impact on both current and future consumers, e.g. through the impact on electricity bills, and social and environmental benefits through carbon savings. We summarise the quantified costs and benefits below and estimate the potential net impact on consumers, while noting that there are a range of factors which determine the extent to which these impacts, which appear at a transmission level, are ultimately passed through to consumers. We also discuss these impacts from the perspective of efficiency and economy, which is relevant to our consideration of CAP148 in relation to the applicable CUSC objectives and our wider duties.

Summary of costs and benefits

3.43. In seeking to quantify the impact on consumers, our analysis assumes that all costs and benefits that apply uniformly to all generators are passed through to consumers. This includes additional transmission costs which are socialised through the current Transmission Charging Methodologies, for example constraints costs and reserve costs which are collected via a uniform BSUoS charge. We assume that accelerated DCW costs, which would apply to DTEC generators only, would not be passed through to consumers since these generators are unlikely to set electricity prices. We discuss below how the impacts might change under alternative assumptions. With this in mind, our quantitative analysis set out above identifies the following costs and benefits associated with the impact of CAP148 which might be expected to ultimately be passed through to consumers:

Benefits

- **Carbon abatement** – value of reduction in greenhouse gas emissions arising from the displacement of thermal plants by accelerated renewable generation
- **Wholesale electricity prices** – value of reduction in electricity prices arising from decreased use of high marginal cost plant as a result of increased renewable generation

Costs

- **ROC payments** – increased ROC payments arising from the increase in renewable generation

- **Constraint payments** – increased constraints costs arising from commissioning of new generation before the full transmission investment required to accommodate them has been completed
- **Additional reserve costs** – costs associated with increased reserve requirement from conventional plants to make up sudden shortfalls, due to the increase in connected capacity of intermittent wind generation.

3.44. Table 3 below summarises the above costs (positively signed) and benefits (negatively signed) we have quantified for each modelled scenario, in terms of their net present value over the whole modelling horizon, calculated with a commercial (nominal) discount rate of 8.38%[27]. Table 3 excludes the following costs considered above:

- **Implementation and ongoing operational costs** – central system and NGET costs associated with CAP148, and in the case of CAP148 Original the industry costs associated with the use of administered constrained payments. These costs have not been quantified but are assumed to be small relative to the other costs.
- **Transmission investment costs** – present value costs of accelerated DCW investment. Our quantitative analysis allocated all these costs to DTEC generators.

3.45. Table 3 shows that in the 4 year Base Case scenario the costs are dominated by the increased constraints costs and ROC payments, which outweigh the benefits from carbon abatement and reduced wholesale electricity prices. While these effects are increased for scenarios with a higher volume of new renewable generation and reduced for those with less new renewable generation, the results show a net cost overall in all the scenarios modelled. The High Coal Price scenario has a different pattern of generation outputs relative to the 4 year Base Case scenario as the new renewable generation displaces more (carbon-intensive) coal generation and less gas-fired generation leading to higher carbon abatement benefits, and despite having similar constraints costs it similarly yields a net cost overall.

3.46. We have also undertaken sensitivity analysis[28] as follows:

- Substituting National Grid's estimate for **constraints costs** from non-renewable generation (present cost £381m), as an alternative to that derived for the 4 year Base Case (present cost £424m), still yields a net present cost overall, at £0.9bn.
- Calculating **carbon abatement** benefits using forecast EU ETS prices and excluding NOx[29] approximately halves these benefits for most of the scenarios modelled, resulting in a higher net cost to consumers. The impact is more significant for the High Coal Price scenario which results in an net present cost of approximately £1bn compared to £0.8bn in Table 3, in which NOx is over-valued in the calculation based on CO2e and the shadow price of carbon.
- Using a social (nominal) **discount rate** of 3.43%[30] increases consumers' present cost in all scenarios, since our analysis suggests the effects of CAP148 are negative for consumers in the future. For the 4 year Base Case scenario the net present cost increases from £0.9bn to £1.4bn.

[27] Consistent with the pre-tax real rate of return of 6.25% allowed to transmission licensees under the current Transmission Price Control, assuming inflation at 2% per year.
[28] See also the additional sensitivity discussed under Impact on Competition.
[29] We have excluded NOx as do not think it is robust to value this at a traded price for carbon.
[30] Consistent with the real discount rate of 1.4% used in Stern Review – Economics of climate change, HM Treasury , assuming inflation at 2% per year

Table 3: Summary of costs and benefits quantified for each modelled scenario

	4 year			3 year	
NPV (£m)	**Base case**	***Low case***	***High coal price***	**Base case**	***High case***
Carbon abatement	-266	*-50*	*-400*	-453	*-832*
Wholesale electricity prices	-386	*-78*	*-366*	-590	*-1,599*
Total benefits	**-653**	***-128***	***-766***	**-1,043**	***-2,431***
Reserve costs	26	*7*	*26*	43	*157*
ROC payments	821	*156*	*821*	1,347	*3,261*
RE Constrained off costs	298	*151*	*298*	472	*3,399*
Non-RE constraint costs	424	*200*	*413*	676	*4,807*
Total costs	**1,569**	***514***	***1,558***	**2,538**	***11,624***
Net cost	**917**	***386***	***792***	**1,495**	***9,193***
Net cost, £/household	35	*15*	*30*	57	*348*

Potential impact on consumers

3.47. Our quantitative analysis suggests that CAP148 does not benefit consumers, since in all scenarios modelled the additional constraints costs and ROC payments more than offset the value of reduced emissions. We also note that the key determinant of the impact of CAP148 is not which variant is adopted, but other factors such as the level of renewables which are able to respond to the incentives CAP148 creates. Taking these factors into account we consider the most likely outcome under CAP148 lies between the results for the 4 year Base Case (NPV cost of £0.9bn) and Low Case (NPV cost of £0.4bn).

3.48. We note that the impacts of CAP148 may change under different charging assumptions. Specifically, there is an interaction between the impacts of CAP148 and the treatment of the additional transmission costs in the transmission charging methodology, as this may not only affect the proportion of the resulting costs which are passed through to consumers but also affect the level of response to the incentives CAP148 creates, and in turn the carbon savings. We discuss this interaction in more detail below where we conclude that even taking this interaction into account, we consider that CAP148 would not lead to a net positive outcome for consumers under any scenario.

3.49. We also note that the impact on ROC payments is based on assumptions as to the design of the RO scheme to apply from 2009. We note that the RO review is ongoing and the detailed design of the scheme may differ to that which we have assumed. If we exclude the impact on ROC payments from our calculations the costs and benefits are more finely balanced. However this does not provide sufficient evidence of a net positive outcome for consumers, when it is noted that our estimates exclude implementation costs and, as discussed below under Impact on Competition, there is a risk that constraints costs will be higher than in our estimates. Our further sensitivity analysis set out below suggests that for the 4 year base case the present value of the constraints costs could be £600m above that set out in Table 3. In addition, as discussed above, our assumption that CAP148 has no effect on imbalance volumes or imbalance prices may mean that our analysis under-estimates the full impact of constraint costs. Further, as noted below under Impact on Sustainable Development, we have not quantified the impact on transmission losses.

Efficiency and economy

3.50. CAP148 may impact on the efficiency of transmission system investment and operation, and on the total cost of supplying electricity demand. In considering CAP148 from the perspective of efficiency and economy it is important to consider whether the additional transmission costs are outweighed by benefits of the proposals, including the value to the consumer of any savings in carbon emissions. As noted above, the transmission charging methodologies would require modification to reflect the implementation of CAP148 and introduction of DTEC. There is a risk of consumers being exposed to inefficient costs unless the transmission charging methodologies allocate costs to the parties which cause them.

3.51. As noted above, in terms of transmission system operation, the accelerated connection of eligible generation is likely to cause or exacerbate constraints until the associated WW are completed. These constraints would be more frequent and of a longer duration the greater the volume of generation capacity in any given year which has firm access rights in advance of WW being completed. This would be likely to increase the costs of system operation and may also reduce the efficiency of system operation. The CAP148 variants which provide for a longer lead time for the allocation of DTEC to eligible generators would enable more time for delivery of network investment, thereby reducing the extent of any system constraints. To the extent that CAP148 leads to a higher volume of intermittent generation connected to the transmission system in any given year, it may also increase reserve costs for that year.

3.52. While the earlier connection of eligible generation would necessitate acceleration in their associated DCW only, it could potentially also impact on investment in WW as National Grid seeks to minimise the additional constraints costs identified above. It may also increase the internal costs of the transmission licensees due to the additional resource requirements associated with connecting eligible generators sooner through the preferential connection arrangements, and operating those arrangements in parallel with the existing arrangements for non-eligible generators. These issues may in turn have implications for the efficient management of the GB queue. CAP148 may also increase the overall level of complexity of the transmission arrangements both for National Grid and for users, particularly under CAP148 Original due to the inclusion of the priority despatch element and application to proportionally qualifying plant.

3.53. Under CAP148 Original it is proposed that the DTEC generators should face the same transmission charges as non-DTEC generators and that the additional constraints costs associated with the administered Interruption Payments should be socialised through TNUoS charges. Under each WGAA constraints costs would continue to be recovered through BSUoS, as is the case now. This may be expected to increase the volatility of BSUoS charges. In the Amendment Report, National Grid states its view that given the potential increase in operational costs for a small increase in connected generation, it would seek to treat DTEC as an additional service and to introduce a cost-reflective charge which targets the additional operational costs to the DTEC generator. This is on the basis that socialisation of the costs would introduce a cross-subsidy from other users to DTEC generators, which would increase the risk of inefficient decisions by users and transmission licensees. We note that some industry parties who supported one or more variant of CAP148 in National Grid's consultation process were of the view that allocating the additional costs back to DTEC generators would undermine the benefits of the proposal in terms of carbon savings.

3.54. As discussed in more detail above, CAP148 may be expected to lead to savings in carbon emissions through displacement of conventional generation by DTEC generation. We note that many of the supporters of CAP148 through National Grid's consultation process argued that the benefits from these savings would be expected to outweigh the additional constraints costs and that CAP148 would have further benefits in terms of wider policy objectives such as the achievement of government targets for the level of renewable generation. We discuss the wider impacts of CAP148 below, and we note that the quantitative analysis set out above suggests that the accelerated connection of DTEC generation leads to additional constraints costs in excess of the carbon abatement value for all the scenarios modelled. This analysis is based on the assumption that the all additional constraints costs are socialised. We have also considered the potential impact under the alternative assumption that these costs are allocated to DTEC generators through cost-reflective charges. We note that even under these assumptions it may still be economic for DTEC generators to connect earlier, however we consider that it is likely that the acceleration rate would be significantly reduced, with a corresponding reduction in the emissions savings and associated carbon abatement value. Therefore we do not consider that the carbon savings would outweigh the additional constraints costs under any scenario.

3.55. We agree that there is an interaction between the treatment of the additional transmission costs associated with CAP148, in particular the increased operational costs, and the incentives on generators eligible for DTEC. We note that this in turn has implications for the other impacts of CAP148. We invite views on the appropriate treatment of DTEC generators in the transmission charging methodologies and on the extent to which the impacts of CAP148 quantified above might vary depending on whether the additional transmission investment and operation costs associated with CAP148 are socialised or allocated to parties which cause them.

Impact on competition

Competition in electricity generation

3.56. The accelerated connection of qualifying generation may have an overall impact on the level of competition in the electricity generation sector, while the differential treatment for those types of generation may have an impact on the ability of generators to compete on a level playing field.

3.57. On the one hand, CAP148 may be expected to have some positive impact on the level of competition in the electricity generation sector. Eligible projects are mainly windfarms the ownership of which is relatively diverse. The accelerated projects do not significantly increase the market share of any of the larger generators. However, any such pro-competitive effect is likely to be relatively minor given that there is a relatively large plant margin in the base-case scenario, with the current ROC subsidy having a much more material impact on the extent to which renewable generators compete on a level playing field with other generation technologies. As noted above the increase in connected renewable generation capacity would be expected to lead to the displacement of conventional generation in the merit order. As a result, plants with higher marginal cost plant would run less often and the average cost of generating electricity would be reduced, with a corresponding reduction in wholesale electricity prices.

3.58. While these potential pro-competitive effects are noted, they are relatively minor and are likely to be outweighed by negative impacts on competition as the differences in treatment for eligible generators under CAP148 affect the ability of generators to compete on a level playing field. Specifically, in accelerating the development of projects eligible for DTEC, each of the CAP148 variants would give eligible renewable generators a competitive advantage over non-DTEC generators in the sense that their projects would be given preferential treatment in terms of system connection, enabling the profits from those projects to be accelerated. This advantage is greater under the CAP148 variants based on a shorter lead time. The “A” and to a lesser extent “B” versions of CAP148 would in principle provide greater certainty as to the connection date for DTEC generators, as they would allow connection even if WW were delayed for reasons beyond NGET’s control. However it is not clear that this is a material advantage given the rarity of such force majeure events. To the extent that the additional transmission costs are socialised rather than allocated to DTEC generators through cost-reflective charges, this would introduce a cross subsidy creating a further competitive advantage for DTEC generators, as well as creating a risk of consumers being exposed to inefficient costs as discussed above. While application of cost-reflective charges might reduce this risk and avoid such a cross subsidy, DTEC generators would retain a competitive advantage through the preferential arrangements for connection which would not be available to other types of plant in the GB queue.

3.59. The competitive advantage for DTEC generators, over and above that already provided by the ROC subsidy for renewable generation, is predominantly associated with the priority connection element of CAP148. Once built, DTEC plants would have no operational advantage over other plant under any of the WGAAs, as DTEC and non-DTEC generation would be treated the same within the Balancing Mechanism. In theory, the priority despatch element of CAP148 Original could be argued to provide an advantage in that DTEC generators are less likely to be constrained off than non-DTEC plants. However being constrained off is not in itself a competitive disadvantage given that generators are compensated for this. Further, as discussed above, in practice the use of priority despatch is unlikely to have a material impact on how often a DTEC plant is constrained off compared to the other CAP148 variants.

3.60. We also note that the increased incidence of constraints under CAP148 may also lead to an increased risk of anti-competitive behaviour by generators in a unique position to relieve those constraints. We have undertaken sensitivity analysis in order to quantify the potential impact of such behaviour and estimated that were generators to increase constrained-on offers by 100% above prices based on marginal costs, then the present value of constraints costs could be about £600m higher than that shown in Table 3 above for the 4 year Base Case scenario. We note that as a minimum, the increased risk of anti-competitive behaviour under CAP148 would have an impact on Ofgem’s burden in terms of monitoring the market so as to detect and, where it is identified, prove the existence of such behaviour and to either seek enforcement or impose financial penalty.

Discrimination issues

3.61. We note that CAP148 explicitly discriminates in favour of generation eligible for DTEC, and as discussed above this creates a competitive advantage over other generation. It is important to consider the question of whether the difference in treatment between eligible generators and other users constitutes due discrimination, when considered in the context of the legal and assessment framework against which we must consider the proposal.

3.62. National Grid must comply with the obligations placed upon it under its transmission licence. Section C of the transmission licence sets out the requirements that directly relate to the system operator. Standard Condition C7 – "Prohibition on discriminating between users" provides that in the provision of use of system or in the carrying out of works for the purpose of connection to the GB transmission system, the licensee shall not discriminate as between any persons or class or classes of persons.

3.63. Situations can arise where differential treatment is lawful. This is sometimes referred to as due discrimination. Equally, differential treatment may be unlawful, and is sometimes referred to as undue discrimination. Undue discrimination is that which consists of treating like cases differently or unlike cases in the same way without justification. It is the identification of relevant similarities (or differences) and the consequences of them along with consideration of justifications for different (or relevantly similar) treatment which is important in assessing whether or not treatment amounts to due or undue discrimination.

3.64. The proposer of CAP148 argues that discrimination in favour of renewable generation (and low carbon generation in the case of other variants of CAP148) as proposed by CAP148 is permitted by the Renewables Directive. In raising CAP148 the proposer argued that it would "prioritise the use of the GB Transmission System by renewable generators, in accordance with Article 7(1) of Directive 2001/77 (the "Renewables Directive")". Article 7(1) of the Renewables Directive provides that:

> *"Without prejudice to the maintenance of the reliability and safety of the grid, Member States shall take the necessary measures to ensure that transmission system operators and distribution system operators in their territory guarantee the transmission and distribution of electricity produced from renewable sources. They may also provide for priority access to the grid system of electricity produced from renewable energy sources. When dispatching generating installations, transmission system operators shall give priority to generating installations using renewable energy sources insofar as the operation of the national electricity system permits."*

3.65. We note that the existing Renewables Directive, therefore, contains a power for Member States to provide for priority access to the transmission system for renewable generators. We also note that Article 7(1) of the Renewables Directive is permissive. A '*permission*' is different from an *obligation* and would require implementation by a Member State before it could have legal effect. Given the absence of any relevant GB implementing measures transposing the permissive aspect of Article 7(1) of the Directive, it is difficult to see how the Renewables Directive can be read to *require* special treatment for such generators. It is therefore relevant to consider how the existing Renewables Directive is accommodated in the relevant legal framework for the Authority's decision on CAP148, bearing in mind the CUSC objectives, the Authority's wider duties, including those arising under European law to ensure non-discrimination (e.g. under Directive 2003/54/EC), and National Grid's licence conditions prohibiting discrimination. In reaching its minded to position the Authority has considered whether the applicable legal and assessment framework would allow for discrimination in favour of renewables (or any other category of generator) in any circumstances.

3.66. In the case of CAP148, it is necessary to consider whether it is reasonable to say that renewables and other generators are relevantly similar so that they should be treated as comparable. If for these purposes they are relevantly similar (perhaps simply because they are each classes of electricity generator) then it may be more difficult to justify differential treatment. If not, then differential treatment may well be justified. In terms of assessing the impact on competition under the applicable CUSC objectives, we consider it is appropriate that the Authority takes as its starting point the approach that all generators should be treated in the same way since they all generate electricity. However, it may be that there are good reasons why renewables should be treated differently but they would need to be properly explained and objectively justified.

3.67. We consider that our existing duties of promoting effective competition would not enable us to approve a CUSC amendment that clearly discriminated in favour of renewable generation, or low carbon generation in the manner of CAP148, unless the difference in treatment is objectively justified. Based on the information available to us at present, in particular our assessment of the impact of CAP148 on consumers and on efficiency and economy as set out above, we have reached a preliminary view that there is no objective justification for discrimination of the type envisaged by CAP148.

3.68. We note that the existing Renewables Directive is currently under review and the existing draft of the new Directive, which may be subject to change, provides that Member States shall prioritise renewable generation, rather than the existing permissive drafting that Member States may prioritise such generation. We consider that any decision on CAP148 should be based on the existing baseline at the time of that decision, and not anticipate the adoption of EU legislation which is at the formative stage. In reaching our final decision, we will carefully consider any views that respondents express in this regard and on the wider discrimination issue.

Impact on sustainable development

3.69. We have considered CAP148 in the context of the five sustainable development themes, set out below, which were identified by the Authority, drawing on the UK Government's Sustainable Development Strategy that set out how Ofgem will contribute to the sustainability agenda[31].

Managing the transition to a low carbon economy

3.70. We consider that the theme of managing the transition to a low carbon economy is particularly relevant to CAP148. Much of the electricity generated in the UK is produced by power stations burning fossil fuels, leading to emissions of greenhouse gases and other pollutants. In recent years electricity generation has accounted for around one third of UK CO2 emissions. There is a clear imperative at EU and domestic level that there needs to be a substantial decrease in the emissions of carbon dioxide from the generation sector. Any proposal which facilitates earlier connection of renewable and/or low carbon generation could potentially help meet the UK's emission reduction commitments under the Kyoto Protocol, and meet the domestic targets of a reduction in CO2 to 20 per cent below 1990 levels by 2010, and 60 per cent below 1990 levels by 2050. Facilitating earlier connection of renewable generation could similarly help attain the European Union's total target of 20% contribution of renewable energy by 2020. The ability to meet the UK's target of 15% by 2020, which as noted above equates to between 35% and 40% of our electricity being

[31] See Ofgem's second annual Sustainable Development Report, November 2007

supplied by renewable generation, could potentially benefit from CAP148. The potential impact of CAP148 on carbon emissions and on the ROC mechanism is set out above, for a range of scenarios as the volume of renewable generation.

3.71. From a sustainable development perspective, another relevant consideration is that removing a part of the bottleneck in the arrangements that has caused the GB Queue may enable faster connection of renewable generation. However it is also worth noting the possibility of ways that may be capable of achieving the aim of providing faster access to renewable generation, and emissions savings, yet would not discriminate unduly between classes of generator or incur the substantial cost increases that ultimately consumers will be expected to pay under CAP148.

Promoting energy savings

3.72. CAP148 may be expected to lead to the displacement of conventional generation by new rewewable generation, thereby reducing the energy intensity of the electricity sector. To the extent that CAP148 increases the volume of electricity generated in the north of GB, it may also lead to an increase in transmission losses, although this is likely to be a second order effect compared to the impact on constraints costs. Our analysis does not quantify the impact on transmission losses.

Eradicating fuel poverty and protecting vulnerable customers

3.73. The Authority has duties in relation to the impact of proposals on the sick, disabled, elderly, those on low incomes and rural customers, as well as to contribute to the achievement of sustainable development. In considering the impact of the proposals, we are required to have regard to BERR (previously DTI) guidance regarding the attainment of social and environmental policies.

3.74. Our initial view is that, further to the issues considered above in relation to sustainable development, the most important consideration from the perspective of social objectives is the overall impact of CAP148 on consumers. Clearly reducing carbon emissions is important for consumers but at a time when energy costs and fuel costs are rising, we must make sure that measures we need to take to tackle climate change aren't any more expensive than they need to be. As we set out elsewhere, under CAP148 there would be a substantial increase in the costs that consumers will be expected to pay, specifically through a substantial increase in constraint costs and an advancement of ROC payments. Even when including the carbon abatement benefit, consumers are likely to be at a substantial financial disadvantage compared to the status quo.

Ensuring a secure and reliable gas and electricity supply

3.75. On the one hand CAP148 is likely to promote greater diversity in electricity supply by encouraging the development of new renewable generation.

3.76. However, a more significant implication of the priority connection element of CAP148 is that for an interim period the GBSO is likely to offer more contractual capacity to the market than can be accommodated by the transmission system. As noted above this would mean that the GBSO would need to constrain more generators off the transmission system to prevent the overloading of transmission lines than is currently the case. Whilst there may not be an appreciable risk to the security of supply as ultimately the amount of generation wishing to export onto the transmission system at any moment in time should match demand, the locational disposition of this generation relative to the capability of relevant transmission lines means a larger number of constraint actions will need to be taken than is currently the case. As the GBSO will be required to take more pre-fault actions, there would be a marginally increased risk that it will not receive the level of response it was expecting to achieve from generators. Where this occurs there could be an increase in the incidence of unplanned transmission line outages, and potentially loss of major transmission infrastructure.

3.77. In more general terms, advancing more renewable generation ahead of wider transmission system reinforcements could present an increased risk to the security of supply in the event that sufficient flexible conventional generation cannot be procured to cover for its unplanned loss. This might be exacerbated if the preferential arrangements for eligible generators deter investment in conventional generation. However, this could be mitigated to a certain extent by the GBSO procuring a greater volume of reserve and response ahead of time, which would in turn result in a further increase in costs to consumers.

Supporting improved environmental performance

3.78. To the extent that CAP148 impacts on investment in the transmission network, or impacts on whether or not a given generation project connects, it may also have broader environmental impacts in terms of visual amenity. In our quantitative analysis we have assumed that CAP148 would not in itself lead to an increase in the ultimate capacity of renewable generation in GB, nor would it affect the nature of the transmission works necessary to connect new generation. Therefore, CAP148 would have the affect of bringing forward any impacts in terms of visual amenity which would have arisen in the absence of CAP148.

3.79. To the extent that CAP148 leads to displacement of conventional generation by renewable generation it may also be expected to have beneficial impacts on air quality by reducing the volume of pollutants emitted from power stations.

Impact on health and safety

3.80. We do not consider that CAP148 will have a significant impact on health and safety.

Risks and unintended consequences

3.81. In addition to the key uncertainties discussed above in relation to the impacts quantified above, which we have addressed though scenario modelling and sensitivity analysis, we note the following potential risks and unintended consequences associated with CAP148:

- The use of administered Interruption Payments under the priority despatch element of CAP148 Original may be considered to be inconsistent with the “pay-as-bid” principles of NETA and BETTA
- Adopting eligibility criteria which include proportionally qualifying plant could have negative implications for the development of co-fired technologies
- CAP148 could deter conventional generation, which is vital to support intermittent generation, from connecting to the system
- CAP148 may potentially exacerbate current issues with respect to the tagging of system actions from the cash out price.

3.82. We invite views on whether there are any further risks and unintended consequences associated with CAP148 which the Authority should consider in reaching its final decisions.

Other impacts including implementation costs

3.83. As part of the industry assessment of CAP148, the potential impacts on industry computer systems and need for consequential changes to core and other industry documents were noted. Given the magnitude and complexity of the potential changes and long lead time for connection of the first generation to be granted DTEC if CAP148 is approved, detailed scoping of these changes was not included in the industry assessment of CAP148, being deferred until after the Authority decision on CAP148. As these impacts were not quantified as part of the industry assessment of CAP148 they are considered here in high level qualitative terms only. We invite views on implementation issues associated with CAP148 including the nature, scope and development timescales for consequential changes.

3.84. As set out in the Amendment Report, all the CAP148 variants would require consequential changes to the System Operator-Transmission Owner Code (STC), SQSS and Transmission Charging Methodologies and potentially also changes to the Balancing and Settlement Code (BSC), Licences, Distribution Connection and Use of System Code (DCUSC) and Distribution Code. The most complex and wide-ranging changes would be required if CAP148 Original were implemented as this would require further changes to the BSC, Grid Code, Balancing Principles Statement and Procurement Guidelines to give effect to the priority despatch and administered interruption payments as well as the treatment of proportionally qualifying generation. CAP148 also has additional implementation and operating costs associated with the administered interruption payments.

3.85. We note that the recommended implementation date for each of the proposals, if approved by the Authority, is 10 Business Days after the Authority decision. The Amendment Report notes that this is based on the assumption that any consequential changes to other documents are completed before the first DTEC holder is physically connected, and subject to National Grid agreeing with the Authority a process for obtaining derogations from the current SQSS prior to the signing any DTEC bilateral agreements. It is envisaged that the consequential changes could be progressed after implementation as the earliest a User could hold DTEC would be at a minimum of three years from the date of implementation. There may be an issue with developing consequential changes specifically in relation to operational systems if the original amendment is implemented as there would be a lead time involved in developing the methodology and processes for calculating administered prices.

4. The Authority's minded-to position

Chapter summary

This chapter sets out the Authority's preliminary assessment of CAP148 against the legal and assessment framework set out in chapter 1, in the light of the impact assessment set out in chapter 3.

Question box

Question 1: Do respondents wish to raise any specific issues regarding the Authority's minded-to position?

Introduction

4.1. This chapter sets out the preliminary assessment of CAP148 against the legal and assessment framework set out in chapter 1, which the Authority has undertaken for the purposes of reaching a minded-to position.

4.2. This preliminary assessment is based on the information contained in the Final Amendment Report for CAP148 and the impact assessment set out in chapter 3 above, and is subject to consideration of any points raised in response to this consultation process.

Applicable CUSC objectives

4.3. Overall, based on the information currently available to us, we do not consider that there is any clear objective justification for the discrimination in favour of eligible generation under any of the CAP148 variants. As such, CAP148 may conflict both with NGET's licence obligations in relation to non-discrimination and our responsibilities to ensure non-discrimination.

4.4. We note that in terms of the economic and efficient operation and development of the transmission system, all CAP148 variants would increase transmission-related costs by assigning firm access rights in advance of WW being completed. The proposals would also introduce complexity and require substantial consequential changes to other documents, particularly under CAP148 Original.

4.5. Even taking into account the potential carbon abatement benefits under the assessment of economic and efficient system operation, based on savings valued at the shadow price of carbon[32], we still consider in relation to the issues identified in paragraphs 4.3-4.4 above each of the CAP148 variants may fail to better facilitate applicable CUSC objective (a), *the efficient discharge by National Grid of the obligations imposed on it by the Act and by the Transmission Licence*.

[32] We note that using the EU ETS price leads to reduced carbon abatement benefits and increases the net cost to consumers.

4.6. We consider that each of the CAP148 variants may also fail to better facilitate applicable CUSC objective (b), *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*. On the one hand, CAP148 may have some positive effects on competition from a market concentration perspective in that it would enable accelerated connection of renewable plant the ownership of which is relatively diverse. However any such pro-competitive effect may be negated and outweighed by the fact that the discrimination inherent in the proposal means that DTEC and non-DTEC generation could not compete against each other on a level playing field. In addition, there may be an increased risk of anti-competitive behaviour by generators in a position to relieve constraints. While there are remedies available to Ofgem to address such behaviour where it is identified, the increased risk of its occurrence is likely to increase costs and regulatory burden.

4.7. Taking the above considerations into account we consider that none of the CAP148 variants would better facilitate the achievement of the applicable CUSC objectives.

The Authority's legal duties

4.8. In terms of the Authority’s duties in relation to sustainable development and the impact on the environment, we note that CAP148 may be expected to give rise to benefits through the acceleration of renewable generation and consequential reduction of greenhouse gas emissions and other pollutants as such generation displaces existing plant. However, we do not consider that these benefits outweigh the negative aspects of CAP148 in terms of impact on consumers, competition and efficiency and economy. Furthermore, in chapter 3 we set out why we have concerns about the discriminatory nature of the arrangements which CAP148 would introduce and our conclusion so far is that that this discrimination cannot be justified in terms of the Renewable Directive.

4.9. Taking the above considerations into account we consider that none of the CAP148 variants would be consistent with the Authority’s legal duties.

The Authority’s principal objective

4.10. In terms of the Authority’s principal objective to protect the interests of consumers, we note that while each of the CAP148 variants may benefit future consumers in terms of reducing carbon emissions, this would be at a cost to current consumers through increased transmission costs and ROC payments which would be ultimately reflected in electricity bills.

4.11. Overall, the Authority currently considers the option available to it which is best calculated to further the principal objective is to reject CAP148 Original and each of the WGAAs.

The Authority’s minded-to position

4.12. For the reasons set out above the Authority is currently minded to reject CAP148, including the CAP148 Original and each of the five Working Group Alternative Amendment proposals.

5. Conclusions and way forward

Chapter Summary

This chapter sets out the Authority's minded-to position with respect to CAP148, and the way forward.

Question box

Question 1: Do respondents have any views on both the process and timetable that are proposed for the Authority making its final decisions on CAP148 and for publishing those decisions?

Conclusions

5.1. The Authority is currently minded to reject CAP148, including the CAP148 Original and each of the five Working Group Alternative Amendment proposals.

5.2. This is our preliminary view only, and we invite respondents to this consultation to present their views on CAP148, together with any further evidence they would like the Authority to consider in reaching its final decision to show that the differential treatment proposed by CAP148 can be justified.

5.3. We are open to respondents putting forward reasons and arguments challenging our analysis of the costs and benefits and such other of our views set out in this document to persuade us to move from our minded-to position. As such, where in this document we refer to Ofgem's or the Authority's views, that is a reference to our preliminary views, and is subject to consideration of any points raised in response to this consultation process.

5.4. We have considered CAP148 in its own right, within the legal framework described in chapter 1 and including the consideration of carbon savings. Clearly reducing carbon emissions is important for consumers but at a time when energy costs and fuel costs are rising we must make sure that measures we need to take to tackle climate change aren't any more expensive than they need to be. We note that there is a wider context for the issues which CAP148 seeks to address, and other initiatives are also seeking to address those issues.

5.5. Together with our preliminary view that CAP148 should be rejected it is also worth noting the possibility of better ways that may be capable of achieving the same aim of providing faster access to renewable generation yet would not discriminate unduly between classes of generator or incur the substantial cost increases that ultimately consumers will be expected to pay. We consider that the work carried out by the industry in relation to CAP148 will be helpful in informing future developments.

5.6. CAP148 is being considered at a time when the industry, Ofgem and the Government are developing proposals for a new regime for transmission access. Ofgem is working hard to ensure that access to the transmission system does not act as a barrier to renewable and other new generation. Our proposals for the reform of the access arrangement include a radical re-design of the existing arrangements, measures to provide appropriate incentives for the transmission operators to build new infrastructure, and short term measures to help minimise the current queue for connections to the grid.

5.7. Whilst we are minded to reject CAP148 including all of the alternatives, we consider that there are better ways of achieving the same or similar benefits as CAP148, without having to resort to prioritising any particular technology. We consider that the Transmission Access Review will provide short and longer term solutions which will allow significant volumes of additional renewable generators timely connections to the network, which will not involve substantial cost increases to consumers, and that will be consistent with the current legal framework.

Way forward and timetable

5.8. This document provides six weeks for respondents to submit any comments.

5.9. The Authority will consider any responses to this consultation before reaching its final decisions. The Authority currently anticipates that it will publish its decisions towards the end of 2008.

Further information

5.10. Appendix 1 sets out both the details for responding to this consultation and the appropriate contact details should you have any questions. It also sets out a list of all the key areas where we have sought respondents' views in this document. Respondents' views are also welcomed on any other aspect of this document.

Appendices

Index

Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by 28 August 2008 and should be sent to:

Cheryl Mundie
Senior Manager – Transmission
Ofgem
70 West Regent Street
Glasgow
G2 2QZ
0141 331 6003
Cheryl.mundie@ofgem.gov.uk

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.6. Next steps: The Authority will consider any responses to this consultation before reaching its final decisions. The Authority currently anticipates that it will publish its decisions towards the end of 2008.

1.7. Any questions on this document should, in the first instance, be directed to Cheryl Mundie (contact details as above).

CHAPTER: One

There are no questions in this chapter.

CHAPTER: Two

Question 1: Do respondents consider that we have appropriately identified the key elements of CAP148 and the key areas of impact?

Question 2: Are there any other factors that respondents would like us to consider, providing comments where possible on the impact of any factors raised?

CHAPTER: Three

Question 1: Do respondents consider we have appropriately identified, and where possible quantified, the impacts of CAP148, including environmental impacts? If not, what additional quantification is required?

Question 2: Do respondents consider that we have appropriately considered the extent to which these impacts may differ between the different CAP148 variants? If not, what further work is required?

Question 3: Do respondents consider that there are additional impacts that have not been fully addressed? Where respondents consider that there are additional impacts, what are these impacts?

Question 4: Do respondents wish to present any additional analysis that they consider would be relevant to assessing the direct and indirect impacts of the proposals?

Question 5: Do respondents have any views on the implementation issues associated with CAP148, including the nature, scope and development timescales for consequential changes to other documents?

Question 6: Do respondents have any views on the appropriate treatment of DTEC generators within the transmission charging methodology, or on the extent to which the impacts of CAP148 might be expected to vary depending on whether the additional transmission costs associated with CAP148 are socialised across all users or allocated to DTEC generators through cost-reflective charges?

Question 7: Do respondents wish to present any alternative arguments on legal grounds in relation to the discrimination issues arising under CAP148?

Question 8: Do respondents consider there are any further risks and unintended consequences associated with CAP148 which the Authority should consider in reaching its final decisions?

CHAPTER: Four

Question 1: Do respondents wish to raise any specific issues regarding the Authority's minded-to position?

CHAPTER: Five

Question 1: Do respondents have any views on both the process and timetable that are proposed for the Authority making its final decisions on CAP148 and for publishing those decisions?

Appendix 2 – Further information on quantitative analysis

Introduction

1.1. This Appendix provides further information on our quantitative analysis of specific impacts of CAP148, including the input assumptions and modelling methodology underpinning that analysis, together with the detailed results referred to in chapter 3.

1.2. As noted in chapter 3, we have had assistance from The Brattle Group ("Brattle") which has undertaken the modelling under Ofgem supervision using its own software and independently sourced data. Brattle has also had access to parts of the additional information provided by National Grid[33], subject to a confidentiality agreement. In this Appendix references to "we" and "our" include references to Brattle unless otherwise stated.

General

1.3. All our quantitative analysis is based on the modelling assumption that CAP148 will be implemented on 1 January 2009. Our modelling horizon is 2012-2020, on the basis that the earliest date a plant could hold DTEC under any scenario is 2012, being three years after the modelled implementation date. All annual results are presented in calendar years and all monetary data in nominal prices assuming 2% inflation. Unless otherwise stated, all present value (PV) data is based on a discount rate of 8.38%, consistent with the pre-tax real rate of return of 6.25% allowed to transmission licensees under the current Transmission Price Control.

Broad approach

1.4. We have derived a profile of connected generation capacity with and without CAP148, by considering the impact of the priority connection element on a project by project basis. To do so we have established a baseline scenario of renewable generation projects that will come online in the absence of CAP148 out to 2020 (the "counterfactual") and then examined how CAP148 might accelerate the connection of a given project within that baseline. Our modelling assumes that CAP148 would not in itself lead to an increase in the ultimate capacity of renewable generation in GB, on that basis that the ultimate capacity will depend strongly on factors such as available sites and available subsidies, and that CAP148 makes only a marginal difference to project economics.

1.5. We have used a merit order model to model short term operation. Taking into account assumptions as to plant availability and marginal costs, the merit order model first calculates the unconstrained outputs of each plant by considering the

[33] Information provided to Ofgem in response to a formal request pursuant to Standard Licence Condition B4 of National Grid Electricity Transmission's electricity transmission licence.

cheapest way of meeting a given level of demand. The modelling then adjusts this pattern of generation to take account of transmission constraints. For each scenario we have analysed the impact of CAP148 by comparing the results with those for the given counterfactual.

CAP148 variants modelled

1.6. As noted in chapter 2, in terms of the priority connection element of CAP148 the six variants (including the Original and the five WGAAs) are distinguished from each other by the option chosen under the three categories of variation, namely the eligibility of generation, the allocation of risk associated with delays and the lead time for connection. In undertaking its quantitative analysis we have focussed on WGAA 4BX, on the basis that this is the only variant for which legal drafting was provided. However, we have also considered the potential impact of varying the choice of option in each of these categories, in order to determine the extent to which further quantitative modelling is required.

1.7. All our modelling is based on the eligibility criterion “4”, i.e. all REGO generation minus proportionally qualifying. However we note that in practice, for the projects in the TEC register, the variations on eligibility result in the same pool of generators able to accelerate under the priority connection element. For example, under eligbility criterion “3”, low carbon generation minus proportionally qualifying, nuclear power would be eligible for DTEC. However the lead time of nuclear power is sufficiently long that any wider works required would be completed before the plant is commissioned. Hence CAP148 would have no effect on the commissioning date of nuclear plant, or other eligible projects with long lead times such as a tidal barrier. In addition, the TEC register contains no proportionally qualifying plant so that there is currently no practical difference between CAP148 variants based on eligibility criteria “1” and “4”, with nearly all of the capacity eligible for DTEC being onshore or offshore wind.

1.8. Under our modelling assumption that CAP148 is implemented on 1 January 2009, the earliest any project could hold DTEC is driven by the lead time applicable to the given CAP148 variant. WGAA 4BX is based on a four year lead time, so that the earliest any given project could hold DTEC is 2013, being four years after the modelled implementation date. Under the three year lead time option the earliest any given project can hold DTEC is 2012, which is 3 years after the assumed implementation date. The three year lead time applies to the Original amendment and the WGAAs based on lead time option “Y”, and the four year lead time applies to the WGAAs based on lead time option “X”. We considered that the choice of lead time can have a significant effect on the impact of CAP148 on connected generation capacity, and has therefore undertaken quantitative modelling for lead times of both three and four years.

1.9. In our quantitative modelling we have not considered the impact of delays in WW on the basis that the probability of delays is highly uncertain and their inclusion could distort the analysis. Therefore the quantitative analysis does not distinguish between the CAP148 variants in this respect.

1.10. Based on the above, we have concluded that the only design feature to make a material difference in this respect is the lead time for allocation of DTEC. Our quantitative analysis for lead times of three and four years are intended to represent WGAA 4CY and WGAA 4BX respectively.

Input assumptions

1.11. For our Base Case we have developed a generation background and network model based on publicly available data from the NGET's 2007 Seven Year Statement (including the four quarterly updates) and TEC Register as of 14 January 2008[34]. In considering the impact of CAP148 we have also developed alternative assumptions as to new renewable generation for the purposes of its other modelled scenarios, and also modelled a scenario which differs from the Base Case only through the fuel price assumptions used.

1.12. In modelling each scenario we have also used assumptions for

- plant closures and further plant additions over the modelling horizon
- time period for a given project to be granted planning consent
- time period between planning consent being granted and a project being commissioned
- limitations on the degree to which CAP148 accelerates connection of eligible generation
- generation marginal costs
- generation operation
- transmission investment beyond the current SYS timescales.

1.13. Details of the scenarios and assumptions used are set out below.

Connected generation

Base Case

1.14. For the Base Case counterfactual we estimate the quantity and type of plants on the system from the SYS and the TEC register. As SYS only extends to 2013/14 and the last year covered by the TEC register is 2018, we have also made assumptions on what further plant would be commissioned beyond these timescales as well as take views of which existing plants might be retired.

1.15. To extend the data from the TEC register beyond 2018 and account for plant being accelerated from beyond 2020 to before 2020, we have estimated in Table A.1 the likely levels of additional renewable generation for the period 2018 to 2024 under the base case counterfactual.

[34] As of the end of June 2008 there have been no significant changes with respect to DTEC qualifying plant between the 14 January 2008 TEC register and the latest available version.

1.16. We have also compared the Base Case counterfactual renewable generation forecast to a report by Oxera commissioned by BERR. Oxera estimated the level of renewable generation likely after reform of the Renewables Obligation (RO) and BERR based its impact assessment of the reformed RO on Oxera's forecasts. We find that the level of qualifying generation in the TEC register exceeds that forecast by Oxera by over 50%. This is perhaps surprising as some of the projects currently in the TEC register will drop out. We note that there is uncertainty as to the volume of new renewable generation in the future and for this reason we have modelled alternative generation background scenarios as described below.

Table A.1: Renewable capacity additions beyond 2018 (Base Case counterfactual)

Additional renewable capacity (MW)		2019	2020	2021	2022	2023
Wind	**Zone 1**	300				
	Zone 2	300	300			
	Zone 4		300			
Offshore wind	**Zone 9**	600	600			
	Zone 10			600		
	Zone 12				600	
	Zone 15					600

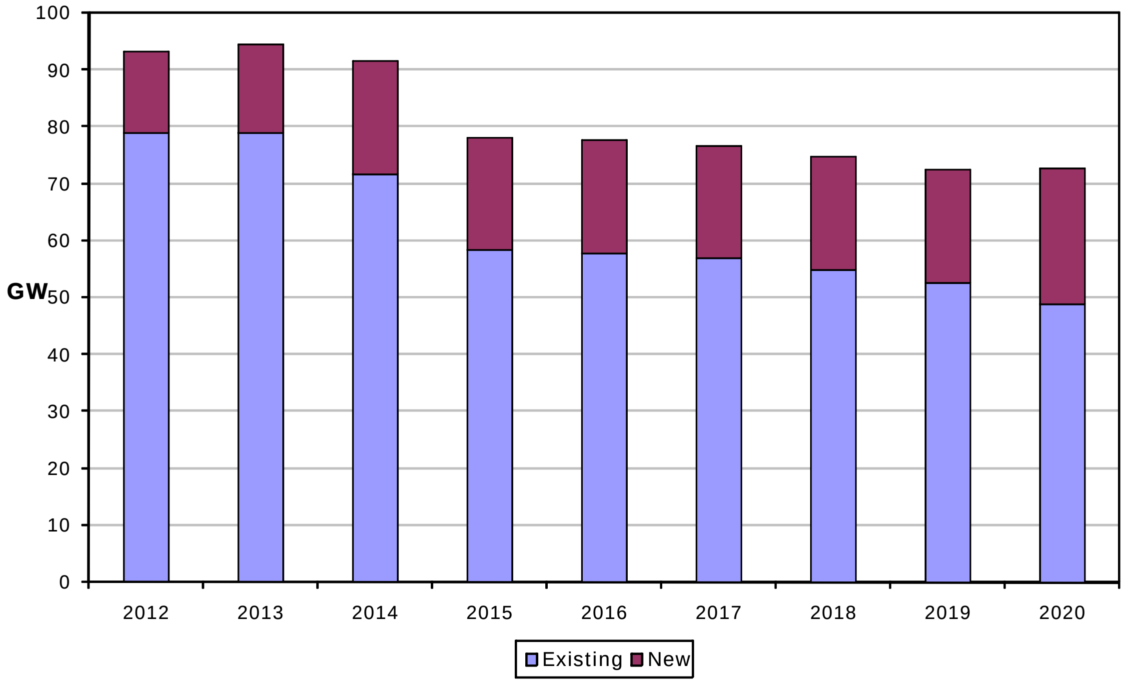
1.17. In modelling plant closures, we assume a lifetime (from the date of commissioning of their last unit) of 40 years for coal plants and 35 years for all other plants except that:

- Nuclear plants are retired in line with the announced schedule;
- Auxiliary gas turbines are retired when the main plants to which they are attached retire; and
- Plants that have opted out of the LCPD retire by 2015.

1.18. In addition to including plant additions included in the Seven Year Statement, we have also added generic new CCGTs in the later years in order to maintain a capacity margin of at least 16%, based on installed capacities for all conventional, hydro and biomass plants and 30% of their installed capacities for wind plants. For our base case scenario, new plant is only added in 2020. This is composed of 4GW of new CCGTs spread across zones 10, 12 and 17.

1.19. Taking into account the above assumptions, the resulting development in non-DTEC capacity under the Base Case scenario is shown in Figure A.1 below, where "existing generation" refers to plants scheduled to be operational in 2009 and "new" refers to the subsequent plant additions.

Figure A.1: Development of non-DTEC generation over time under the Base Case scenario



Alternative generation background scenarios

1.20. In considering the impact of CAP148 on connected generation capacity, we have modelled the following alternative scenarios as to the level of renewable generation and the proportion which is accelerated under CAP148, in each case for both a three year and four year lead time:

- **Base Case** – counterfactual includes all projects in the TEC register; under CAP148 it is assumed all projects that could accelerate do so (as described above)
- **High Case** – counterfactual assumes 38% of electricity to be generated by renewable sources by 2020, representing a "stretch target" modelled by increasing renewable generation capacity in each zone of the Base Case in proportion to the TEC capacity in that zone; under CAP148 it is assumed that all projects that could accelerate do so
- **Low Case** – counterfactual assumes a 50% dropout rate of projects in the TEC register, modelled by 50% less new renewable generation than in the Base Case; in addition it is assumed that only 50% of the volume of eligible generation in the counterfactual is able to accelerate under CAP148.

1.21. In each of the above alternative generation background scenarios the assumptions as to plant closures are the same as in the base case scenario. In terms of new plant additions, as well as including plant additions included in the Seven Year Statement we have again added generic new CCGTs in the later years in order to ensure that the capacity margin never falls below around 17%. Table A.2 below shows how our assumptions on generic plant additions vary across the various different scenarios.

Table A.2: Generic non-DTEC capacity additions by scenario

Additional non-DTEC capacity (MW)	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Base case							4000
Low case					600	600	4800
High case							

Planning consent

1.22. For the base case scenario we have modelled a 2 year gap between planning consent being granted and the project being commissioned and has applied the following broad assumptions as to when projects will be granted planning consent based on their status in the TEC register, based on information provided by the British Wind Energy Association:

- If listed as "under consideration" or "application refused", planning consents will be granted in 6 years
- If listed as "scoping" or "no information", planning consents will be granted in 4 years.

Limitations on acceleration

1.23. In determining limitations on the degree to which CAP148 accelerates connection of eligible generation, we have made the following assumptions applicable to all scenarios:

- In the absence of CAP148, eligible generators will not connect until relevant contingent transmission works have been completed
- CAP148 will only benefit projects planned to connect in 2013 or later (under the modelling assumption that CAP148 is implemented on 1 January 2009)
- No project's connection is accelerated by more than 4 years from the original contracted commissioning date.

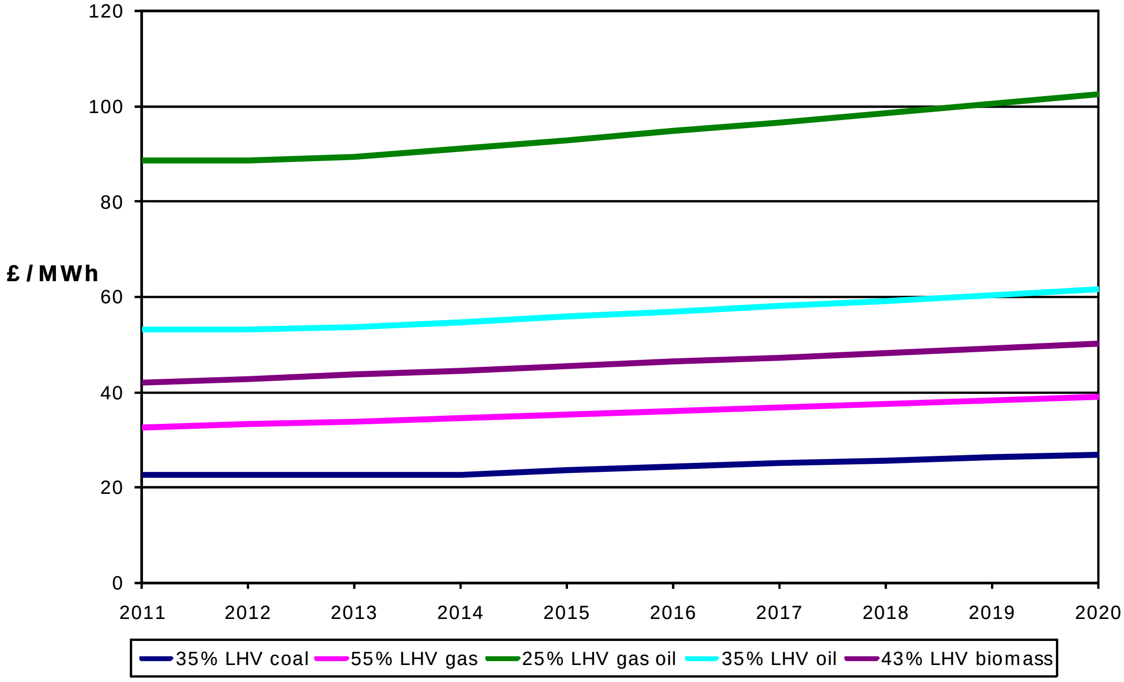
Generation operation

Marginal generation costs

1.24. We calculate marginal generating costs for each conventional plant on the basis of fuel and carbon costs, fuel delivery costs and plant efficiencies.

1.25. Our fuel price assumptions are shown in Figure A.3 below. We assume that coal burnt in GB power stations will be priced to be competitive with international coal traded at the main European hub: Amsterdam/Rotterdam/Antwerp (ARA). To derive an estimate of the ARA prices, we use price forecasts up to 2030 from the US Department of Energy (DoE) Report. To use this data, it is adjusted by adding to each forecast the average of the annual differences between the EEX ARA Coal Year Futures and DoE prices for the period 2009-2014. Under this assumption the ARA price is 55 £/tonne in 2011, and ignoring fuel delivery costs, this equates to a fuel cost of 22.7 £/MWh for a plant with an LHV efficiency of 35% - as shown in Figure A.3. For biomass, we have taken the 2006 marginal cost of 38 £/MWh reported by Ernst & Young in its study for BERR[35] and assumed that this will increase in line with inflation.

Figure A.3: Base scenario fuel cost assumptions (excluding delivery costs)



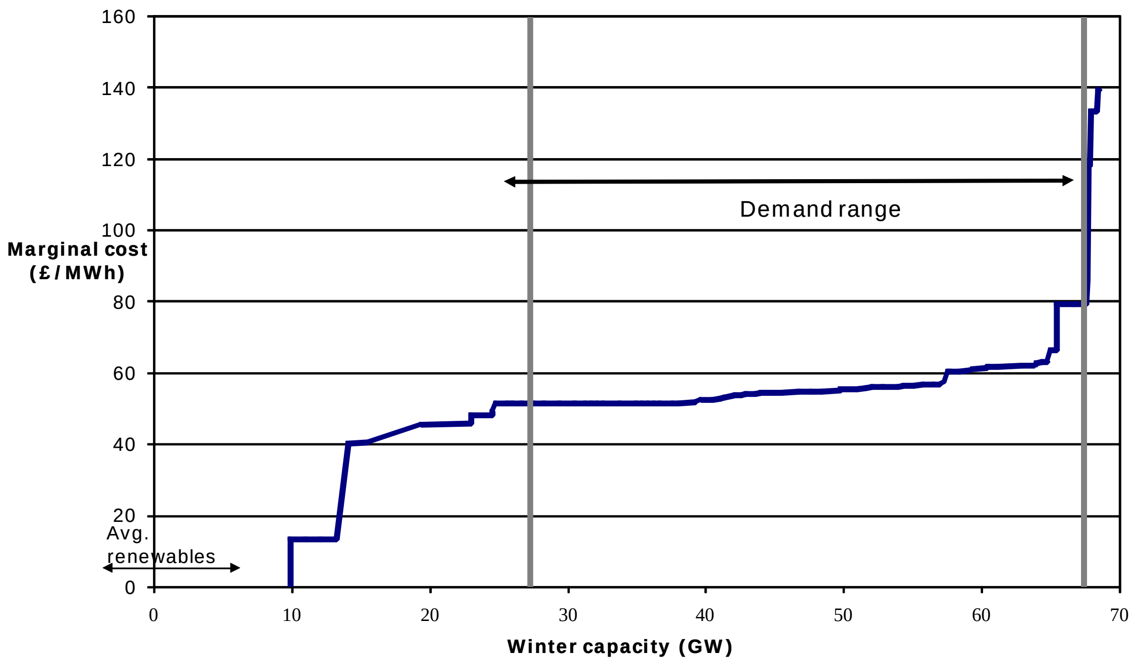
1.26. We begin modeling in 2011, beyond the end of the forward curve for gas and even for crude oil. Therefore, a 2011 gas price has been derived by inflating the GB forward gas price for the summer and winter of 2010 (the latest delivery-date traded). This results in an average 2011 gas price of 52.7 p/therm or 32.7 £/MWh for a plant with an LHV efficiency of 55%. Whilst we accept that gas prices vary by month, it has, for simplicity, only included an annual average gas price in our analysis. Crude oil forward curves out to 2012 were taken from NYMEX results for 11 February 2008. We used historical correlations between crude prices and gas oil and high and low sulphur fuel oil prices (HSFO and LSFO) to produce oil product (distillate) prices based on the forward curve. For the years after 2012, we assume that all oil product prices would move in line with inflation.

[35] Ernst & Young, Impact of Banding the Renewables Obligation – Costs of electricity production, April 2007, URN 07/948.

1.27. We have included an allowance for carbon costs in its marginal cost calculations. Based on a recent report by BERR,[36] we have used carbon prices of €20/tonne CO2 until 2012 and €25/tonne CO2 thereafter and a constant exchange rate of 0.7 £/€.

1.28. Figure A.4 below shows the resulting winter merit order for 2020 under our Base Case counterfactual.

Figure A.4: Winter merit order for 2020 under Base Case counterfactual



Alternative fuel price scenario

5.11. In considering the impact of CAP148 on short term operation, we have modelled the following additional scenario which provides an alternative estimate of the impact of CAP148 under the 4 year Base Case generation background scenario:

- **High coal price** – all assumptions are identical to 4 year Base Case with the exception of the coal prices used (which are 50% higher than in the Base Case), with the effect that coal plant is marginal more often and renewable generation displaces more coal generation and less gas-fired generation than in the Base Case scenario, i.e. the same generation background but different operational outcomes.

[36] BERR, Updated Energy and Carbon Emissions Projections – The Energy White Paper, February 2008

Operating assumptions and costs

1.29. Table A.3 shows the assumptions that we have made concerning the availability of conventional plants and their variable O&M and BSUoS costs (variable transportation costs are treated on a plant-by-plant basis). Costs are assumed to increase in line with inflation at 2% per annum.

Table A.3: Operating assumptions and costs for conventional plants

Fuel	*Forced outages*	*Maintenance*	*Variable costs 2005 £/MWh*
Coal	6.0%	6.6%	3.9
Gas	4.0%	5.5%	2.4
Nuclear	8.0%	12.0%	9.9
Oil	4.0%	5.5%	2.9

1.30. We assume that during the winter (Jan-Mar, Oct-Dec), the available capacity of existing plants is equal to their installed capacity adjusted for their forced outage rate i.e. a 100 MW plant with a forced outage rate of 4% would have an available capacity of 96 MW = 100x(1-4%). During the summer, their availability is further reduced to allow for maintenance which, for simplicity, is assumed to reduce their availability in a similar manner to forced outages. However, plants that have opted out of the LCPD and hence can only generate for a maximum of 20,000 hours from 2008 onwards are assumed to be wholly unavailable during the summer months.

Merit order modelling

Unconstrained generation

Demand

1.31. We model three characteristic days per month – a weekday, Saturday and Sunday – and derive starting values for the demand in each hour of these characteristic days from the 2007 GB half-hourly demand data published by NGET on its website. We then increase demand data to match NGET's base scenario values for ACS peak demand from its 2007 SYS until 2013/14. Thereafter, we assume that peak demand grows at the average of the growth rate from 2009/10 to 2013/14.

Hourly availability of renewable plants

1.32. The merit order model assumes that all renewable plants, whether qualifying for DTEC or not, will be dispatched before other plants on the grounds that either their actual or "effective" marginal costs are lower than for conventional plants. By "effective" marginal cost we mean the marginal cost taking into account the opportunity costs associated with not generating and forfeiting potential ROC payments.

1.33. We estimate the availability of wind plants using assumptions on (a) the day/night split in typical capacity factors[37] taken from a paper by the Environmental Change Institute at the University of Oxford[38] and (b) monthly capacity factors taken from a study of 2005 ROC data by Oswald Consultancy Ltd.[39] The analysis of 2005 ROC data did not include capacity factors for all the zones in which wind plant are likely to be built i.e. Z12, Z16 and Z17, and for these zones we assumed monthly capacity figures equal to those for Denmark quoted in the Oswald Consultancy presentation. For offshore wind, we assume monthly capacity factors that were 5 percentage points higher than those for onshore wind farms in the same zones.

1.34. For hydro plants, we assumed monthly capacity factors based on data from Ireland (we could find no published monthly hydro output data) and then profiled these over the course of a day so that the maximum output was produced between 0700:-10:00 and 16:00-19:00, with somewhat lower output levels between 10:00 and 16:00 and significantly lower levels overnight.

1.35. We assumed that the forced outage rates for biomass plants would be the same as for coal plants and estimated winter and summer available capacities in the same way as for conventional plants.

Modelling constraints

1.36. We have estimated the impact of CAP148 on the extent and cost of boundary constraints by placing limits on the extent of flows from one study zone to another across boundaries defined in the SYS. Such constraints will not necessarily disappear after the wider reinforcement works associated with connecting qualifying plants are completed.

1.37. We model the effects of boundary constraints using the merit order model. We use actual or estimated data on which zone each plant is situated in and projections of the peak demand in each zone, to estimate the balance between supply and demand in each characteristic hour by assuming that the hourly profile of demand in each zone follows that of demand in GB overall. Figure A.5 shows the simplified zonal flow analysis that we use to determine which plants need to be constrained on an off. It shows, for example, that in calculating the situation in zone Z11, we take account of imports from zones Z9 and Z10 and use boundary B17 as the limit for exports from it.

[37] A capacity factor of 0.7 for an hour means that the output of a plant will be equal to 70% of its installed capacity.
[38] Wind Power and the UK Wind Resource, Environmental Change Institute at the University of Oxford, 2005.
[39] Oswald Consultancy Ltd., October UK wind farm performance 2005, based on Ofgem ROC Data, November 2006.' Note that we took the average of the monthly capacity figures shown by region in this report, excluding any obvious outliers.

1.38. Given the limits implied by the choice of boundaries and flow directions, we minimise the cost of generating the required demand subject to the following constraints: (a) total generation matches system demand, (b) generation within a zone plus inflows minus outflows equals the zonal demand and (c) flows across each boundary do not exceed the boundary limits. It is important to note that we assume that the system is balanced i.e. as much generation has to be constrained on as is constrained off. This is consistent with the way in which we model the unconstrained position but we acknowledge that historically the system has often been long. Had we assumed that the system would be long, unconstrained costs would have been higher but more plant would have been constrained off so that, overall, it does not seem likely that the results would change significantly. Indeed, for the base case scenario, we investigated what would happen if the market was consistently long and found that it made no material difference to the change in the constraint costs with and without CAP148.

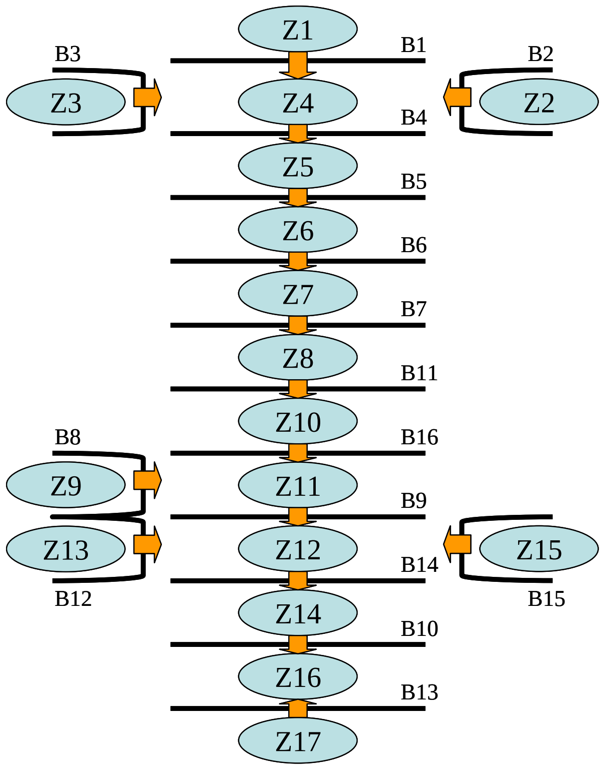
1.39. When renewables plants are constrained off, they forego ROC payments they would otherwise have earned and so we assume that their bid prices in the Balancing Mechanism will equal their costs of production minus the ROC price. An explanation of how we estimate ROC prices with and without CAP148 is set out in chapter 3. We assume that wind and hydro plants have very low production costs, of around £1/MWh, which represent ‘wear and tear’ on the turbines. We further assume that the production costs of offshore wind plants have slightly higher production costs than onshore wind plants, which in turn have slightly higher production costs than hydro plants and, in this way, create a merit order for constraining off renewable generation.

1.40. The above reasoning indicates that conventional fossil-fired plants (except CHP and nuclear) would be constrained off first (with or without CAP148). Since they have relatively high marginal costs and no ROC opportunity costs, they have the lowest constrained off bids. Renewables plants are constrained off next, starting with biomass plants, and nuclear and CHP plants are constrained off last. Hence while CAP148 Original calls for qualifying plants to have priority despatch i.e. for them to be constrained off only after non-qualifying plant have been constrained off, in reality the ROC system means that this happens anyway. Consequently, in the modelling of the order in which plants are constrained off we makes no distinction between CAP148 Original and the WGAAs in its analysis. We acknowledge that the position of qualifying and non-qualifying renewable generators would be different between CAP148 Original and the WGAAs but have not investigated this issue.

1.41. For the base case scenario, we assume that constrained on plants submit offer prices equal to their marginal costs. We acknowledge that, in practice, generators may submit offers above their marginal costs and has investigated the impact of increasing all constrained on offer prices as a sensitivity.

1.42. In adjusting the pattern of generation to take account of constraints, we also take account of the impact of these changes on emission levels.

Figure A.5: Diagram of simplified zonal flow analysis used in the analysis



Comparison with National Grid estimates of constraints costs

1.43. The Amendment Report included illustrative calculations of the impact of CAP148 on constraints costs. These costs were calculated from a spreadsheet model that was originally provided by National Grid to working group members to allow them to enter alternative values for a range of parameters and assess the costs for different scenarios. These estimates, prepared by National Grid, considered the impact of CAP148 for a three year lead time under a given set of assumptions, which are set out and discussed in more detail in the Working Group report. We have compared our analysis with National Grid's estimates, as follows.

1.44. National Grid estimated that with 100% of plant eligible for DTEC advancing their connection dates by 3 years, additional constraint costs over the period 2011/12-2018/19 would total £542 million. Note that this number is simply the sum of the costs for individual years, which are in real terms. Therefore it is not equivalent to the present value costs and benefits we quote throughout this report and in our summary tables. Using the estimates of additional constraint costs per year provided by National Grid, we estimate National Grid's numbers yield a present value cost of about £381 million. This is calculated using a real discount rate of 6.25%, consistent with NGET's real numbers[40].

[40] Noting that in accounting terms, on an NPV basis, the costs in nominal terms using a nominal discount rate equal the costs in real terms using a real discount rate.

1.45. We note that the present value cost of £381 million is significantly less than the constraint costs (over both renewable and non-renewable generation) we estimate in our Base Case scenarios. We note that in separate information supplied to Ofgem, National Grid estimated the total constraints at around 55 TWh, whereas we estimated boundary constraints of around 20 TWh. We have investigated these differences as follows, taking into account the additional information provided by National Grid.

1.46. One of the differences between our approach and National Grid's is that National Grid only assumed that conventional (non-renewables) plants were constrained. We also accounted for the need to constrain off renewable plants, and estimate that these costs are around £472 million in the 3 year Base Case and £298 million in the 4 year Base Case. Recognising this, our sensitivity analysis described in chapter 3 uses the estimate (present value cost £381m) based on National Grid's analysis as an alternative estimate for the impact of CAP148 on constraints costs from non-renewable generation to that derived from our modelling for the 4 year Base Case (£424 million).

1.47. National Grid's estimate of constraints focused on historical constraint information for the Scotex and Peterhead boundaries. While this approach is very reasonable – since this boundary would cause many of the constraints – our model considers constraints between each zone, and so may be expected to predict higher constraint costs in general.

1.48. In its response to Ofgem's information request National Grid explained that they based their estimate of constraint costs on historical constraint data. National Grid estimated the frequency with which constraints might bind (the 'incidence factor') and also estimated how the frequency of constraints might increase with installed wind capacity in the north of Scotland. In its analysis, National Grid used an incidence factor of 15%. However, National Grid's numbers in the response to the information request show that for many of the years the additional installed wind capacity with CAP148 is close to 3,300 MW and the incidence factor increases to 62% if this amount of wind capacity is added. Subsequently, National Grid provided us with the spreadsheet model they used to produce the estimate of £542 million in the amendment report. We found that increasing the incidence factor to 62% in NGET's model increased the sum of the estimated constraint costs from £542 million to about £2,200 million. This number is significantly higher than the constraint costs we estimate. Hence we conclude that reasonable changes in National Grid's assumptions to represent a wider set of scenarios, produce constraint costs which are similar or in excess of our estimates. Accordingly, we conclude that while the constraint costs we estimate are generally larger than those estimated by NGET in its amendment report, the differences can be explained with relatively minor changes to NGET's modelling assumptions.

1.49. In addition, the approach to transmission reinforcements in our model beyond 2013/14 is different to that adopted by National Grid. We assumed that transmission investment would only be undertaken to the extent needed to increase boundary limits to the point at which constraint costs without CAP148 remain broadly constant in real terms. National Grid assumed that the system capacity would increase at the current rate. Hence, our approach to additional transmission capacity planning will probably result in higher constraint costs than National Grid's.

1.50. We note that CAP148 would increase the volume of electricity generated in the north of GB, and hence increase losses. However we did not include these additional losses in our calculations.

Detailed results

1.51. The detailed scenario results referred to in chapter 3 are set out below.

Connected generation capacity

Table A.4: Impact on connected renewable generation capacity

Increased renewable capacity (MW)		**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
4 year	**Base case**	**0**	**144**	**488**	**462**	**3081**	**4391**	**2400**	**1500**	**1200**
	Low case	*0*	*144*	*224*	*208*	*802*	*1080*	*579*	*362*	*289*
3 year	**Base case**	**94**	**910**	**488**	**3758**	**4581**	**5291**	**3000**	**2100**	**1800**
	High case	*94*	*3015*	*1442*	*13745*	*16961*	*19761*	*11250*	*7875*	*6750*

Table A.5 - Breakdown of results by renewable technology for 4 year Base Case

Increased renewable capacity (MW)		**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
4 year	Wind	0	144	488	462	2575	3285	1200	300	0
base	Offshore wind	0	0	0	0	0	600	1200	1200	1200
case	Biomass	0	0	0	0	500	500	0	0	0
	Hydro	0	0	0	0	6	6	0	0	0

Short term operation

Table A.6: Impact on wholesale electricity prices

Reduction in wholesale electricity price (£/MWh)		**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
4 year	**Base case**	**0.0**	**0.0**	**0.0**	**0.1**	**0.5**	**0.7**	**0.4**	**0.3**	**0.1**
	Low case	*0.0*	*0.0*	*0.0*	*0.0*	*0.1*	*0.1*	*0.1*	*0.0*	*0.0*
	High coal price	*0.0*	*0.0*	*0.0*	*0.0*	*0.5*	*0.6*	*0.4*	*0.3*	*0.2*
3 year	**Base case**	**0.0**	**0.1**	**0.0**	**0.6**	**0.7**	**0.8**	**0.4**	**0.4**	**0.1**
	High case	*0.0*	*0.4*	*0.2*	*1.7*	*1.9*	*2.3*	*1.0*	*0.6*	*0.2*

Table A.7: Impact on constraint volumes

Increase in constrained on/off volume (TWh)		2012	2013	2014	2015	2016	2017	2018	2019	2020
4 year	**Base case**	**0.0**	**0.2**	**1.2**	**0.8**	**13.9**	**16.3**	**2.6**	**0.5**	**0.1**
	Low case	*0.0*	*0.5*	*1.3*	*1.1*	*4.9*	*5.0*	*1.3*	*0.5*	*0.0*
	High coal price	*0.0*	*0.2*	*1.2*	*1.0*	*15.1*	*17.1*	*2.7*	*0.7*	*0.0*
3 year	**Base case**	**0.2**	**1.4**	**1.2**	**15.9**	**16.6**	**16.8**	**2.5**	**0.4**	**0.1**
	High case	*0.1*	*15.3*	*8.4*	*83.5*	*83.2*	*86.0*	*20.9*	*6.6*	*-0.6*

Table A.8: Impact on constraint costs

Increase in constraint costs (£m)		2012	2013	2014	2015	2016	2017	2018	2019	2020
4 year	**Base case**	**0**	**2**	**22**	**16**	**615**	**716**	**65**	**0**	**-1**
	Low case	*0*	*16*	*56*	*58*	*232*	*241*	*58*	*18*	*-1*
	High coal price	*0*	*0*	*15*	*15*	*612*	*711*	*61*	*1*	*-1*
3 year	**Base case**	**2**	**15**	**22**	**644**	**726**	**716**	**65**	**-2**	**-2**
	High case	*2*	*759*	*399*	*4265*	*4214*	*4422*	*1146*	*383*	*-15*

Table A.9: Change in output from renewable generation

Change in RE generation (TWh)		2012	2013	2014	2015	2016	2017	2018	2019	2020
4 year	**Base case**	**0.0**	**0.5**	**1.6**	**1.6**	**7.4**	**10.0**	**6.6**	**3.3**	**1.8**
	Low	*0.0*	*0.4*	*0.2*	*0.2*	*1.2*	*1.8*	*1.2*	*0.6*	*0.4*
	High coal price	*0.0*	*0.5*	*1.6*	*1.6*	*7.4*	*10.0*	*6.6*	*3.3*	*1.8*
3 year	**Base case**	**0.3**	**3.2**	**1.6**	**9.5**	**10.4**	**13.0**	**6.8**	**4.9**	**2.1**
	High	*0.3*	*2.5*	*1.0*	*17.3*	*25.9*	*34.4*	*16.0*	*14.2*	*7.7*

Table A.10: Change in output from coal generation

Change in coal generation (TWh)		2012	2013	2014	2015	2016	2017	2018	2019	2020
4 year	**Base case**	**0.0**	**-0.4**	**-1.2**	**-0.3**	**-1.6**	**-1.8**	**-0.6**	**-0.2**	**-0.1**
	Low	*0.0*	*-0.3*	*-0.2*	*0.0*	*-0.3*	*-0.3*	*-0.1*	*-0.1*	*0.0*
	High coal price	*0.0*	*-0.3*	*-0.8*	*-0.5*	*-2.8*	*-3.7*	*-1.8*	*-0.7*	*-0.4*
3 year	**Base case**	**-0.2**	**-2.3**	**-1.2**	**-2.7**	**-1.9**	**-1.8**	**-0.6**	**-0.3**	**-0.1**
	High	*-0.3*	*-1.9*	*-0.8*	*-5.1*	*-3.6*	*-3.8*	*-0.1*	*-0.1*	*-0.1*

Table A.11: Change in output from gas generation

Change in gas generation (TWh)		2012	2013	2014	2015	2016	2017	2018	2019	2020
4 year	**Base case**	**0.0**	**-0.2**	**-0.4**	**-1.3**	**-5.4**	**-7.7**	**-5.9**	**-3.0**	**-1.7**
	Low	*0.0*	*-0.1*	*0.0*	*-0.1*	*-0.7*	*-1.3*	*-1.0*	*-0.5*	*-0.4*
	High coal price	*0.0*	*-0.2*	*-0.9*	*-1.1*	*-4.2*	*-5.9*	*-4.7*	*-2.6*	*-1.4*
3 year	**Base case**	**-0.1**	**-0.9**	**-0.4**	**-6.5**	**-8.0**	**-10.8**	**-6.2**	**-4.4**	**-1.9**
	High	*-0.1*	*-0.5*	*-0.2*	*-4.3*	*-12.4*	*-19.9*	*-15.8*	*-14.1*	*-7.6*

Environment

Table A.12: Reduction in CO_2

Reduction in CO2 (Mt)		2012	2013	2014	2015	2016	2017	2018	2019	2020
4 year	**Base case**	**0.0**	**0.4**	**1.2**	**0.7**	**3.1**	**4.0**	**2.6**	**1.3**	**0.7**
	Low case	*0.0*	*0.3*	*0.2*	*0.1*	*0.4*	*0.7*	*0.5*	*0.3*	*0.2*
	High coal price	*0.0*	*0.3*	*0.9*	*0.8*	*3.7*	*5.0*	*3.2*	*1.6*	*0.9*
3 year	**Base case**	**0.2**	**2.3**	**1.2**	**4.4**	**4.2**	**5.1**	**2.7**	**2.0**	**0.8**
	High case	*0.3*	*1.8*	*0.7*	*5.5*	*6.9*	*9.6*	*5.6*	*5.0*	*2.8*

Table A.13: Reduction in CO_2e

Reduction in CO2e (Mt)		2012	2013	2014	2015	2016	2017	2018	2019	2020
4 year	**Base case**	**0.0**	**0.4**	**1.2**	**0.7**	**3.2**	**4.1**	**2.6**	**1.4**	**0.7**
	Low case	*0.0*	*0.3*	*0.2*	*0.1*	*0.5*	*0.7*	*0.5*	*0.3*	*0.2*
	High coal price	*0.0*	*0.5*	*1.3*	*1.0*	*5.3*	*6.9*	*3.8*	*1.9*	*1.0*
3 year	**Base case**	**0.2**	**2.6**	**1.2**	**4.6**	**4.3**	**5.2**	**2.7**	**2.1**	**0.8**
	High case	*0.3*	*3.0*	*1.3*	*7.0*	*8.1*	*10.9*	*6.1*	*5.3*	*2.8*

Table A.14: Carbon abatement value using CO_2e and Shadow Price of Carbon

Carbon abatement value (£m)		2012	2013	2014	2015	2016	2017	2018	2019	2020
4 year	**Base case**	**0**	**13**	**42**	**24**	**115**	**157**	**104**	**57**	**31**
	Low case	*0*	*11*	*7*	*3*	*17*	*27*	*18*	*11*	*7*
	High coal price	*0*	*15*	*43*	*35*	*192*	*261*	*150*	*77*	*44*
3 year	**Base case**	**8**	**82**	**42**	**160**	**157**	**199**	**107**	**84**	**36**
	High case	*9*	*96*	*42*	*244*	*295*	*413*	*240*	*215*	*119*

Table A.15: Carbon abatement value using CO_2 and forecast EU ETS price

Carbon abatement value (£m)		2012	2013	2014	2015	2016	2017	2018	2019	2020
4 year	**Base case**	**0**	**7**	**22**	**12**	**55**	**72**	**46**	**24**	**13**
	Low case	*0*	*6*	*4*	*1*	*8*	*12*	*8*	*5*	*3*
	High coal price	*0*	*8*	*23*	*18*	*92*	*121*	*67*	*33*	*18*
3 year	**Base case**	**4**	**45**	**22**	**80**	**75**	**92**	**48**	**36**	**15**
	High case	*5*	*52*	*22*	*122*	*142*	*191*	*106*	*92*	*49*

Table A.16: Change in ROC production

Change in ROC production (TWh)		2012	2013	2014	2015	2016	2017	2018	2019	2020
4 year	**Base case**	**0.0**	**0.5**	**1.6**	**1.6**	**7.4**	**11.0**	**8.6**	**4.4**	**2.7**
	Low case	*0.0*	*0.4*	*0.2*	*0.2*	*1.2*	*2.1*	*1.6*	*0.9*	*0.6*
	High coal price	*0.0*	*0.5*	*1.6*	*1.6*	*7.4*	*11.0*	*8.6*	*4.4*	*2.7*
3 year	**Base case**	**0.3**	**3.2**	**1.6**	**9.5**	**11.4**	**15.0**	**8.9**	**6.7**	**3.1**
	High case	*0.0*	*0.2*	*1.0*	*0.9*	*16.2*	*30.6*	*22.4*	*12.6*	*10.1*

Table A.17: Additional ROC costs

Extra ROC payments (£m)		2012	2013	2014	2015	2016	2017	2018	2019	2020
4 year	**Base case**	**0**	**22**	**70**	**68**	**327**	**496**	**395**	**210**	**129**
	Low case	*0*	*15*	*10*	*7*	*52*	*93*	*76*	*42*	*31*
	High coal price	*0*	*22*	*70*	*68*	*327*	*496*	*395*	*210*	*129*
3 year	**Base case**	**14**	**136**	**70**	**413**	**506**	**680**	**413**	**318**	**148**
	High case	*14*	*105*	*41*	*755*	*1315*	*1893*	*1103*	*1002*	*555*

Appendix 3 – The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[41]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[42].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of consumers, present and future, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them[43]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[44]

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

[41] entitled "Gas Supply" and "Electricity Supply" respectively.
[42] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[43] under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.
[44] The Authority may have regard to other descriptions of consumers.

- Promote efficiency and economy on the part of those licensed[45] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity;
- Contribute to the achievement of sustainable development; and
- Secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- The effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- The principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- Certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[46] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[45] or persons authorised by exemptions to carry on any activity.
[46] Council Regulation (EC) 1/2003

Appendix 4 – Legal and assessment framework

Introduction

1.1. This Appendix summarises the legal and assessment framework for amendments to the Connection and Use of System Code (CUSC).

Procedure for proposing amendments to the CUSC

1.2. The CUSC sets out the standard commercial terms between generators (and other network users) and National Grid. The CUSC also sets out the set series of procedures which must be followed in relation to proposals to amend the CUSC. Anyone who is party to the CUSC can propose an amendment to the CUSC. Once a CUSC amendment proposal has been raised, the CUSC Panel assess it before referring it to the Authority for a decision.

1.3. Any proposed amendment to the CUSC should address a defect and must better facilitate the achievement of the applicable CUSC objectives than the existing CUSC baseline. These objectives[47] are;

a. The efficient discharge by National Grid of the obligations imposed on it by the Act[48] and the Transmission Licence; and

b. 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.

1.4. Where the CUSC Panel considers it necessary, particularly for more complex amendments, a working group may be created to fully consider a proposal. Any member of the working group may propose a working group alternative amendment proposal. A working group's findings will be contained in a working group report which is then consulted on. Any CUSC party may raise a consultation alternative amendment at this stage[49]. Each proposal and alternative amendment will be assessed and voted upon by the CUSC Panel before the Final Amendment Report is submitted to the Authority. The Final Amendment Report includes the recommendation from the Panel on whether or not the proposal or alternatives should be made on the basis of whether each of the individual proposals better facilitate the applicable CUSC objectives when compared against the current baseline. It also includes a proposed implementation date in the event that the proposal is approved by the Authority.

[47] The applicable CUSC objectives are set out in standard licence condition C3 of the electricity transmission licence of National Grid Electricity Transmission plc ("NGET").
[48] As set out in the Utilities Act 2000.
[49] The ability to raise a consultation alternative amendment is currently the subject of a CUSC modification (CAP160).

1.5. CUSC amendment proposals are also assessed in the context of section 9 of the Electricity Act 1989. This requires transmission licensees to:

- Develop and maintain an efficient, co-ordinated and economical system of electricity transmission; and
- Facilitate competition in the supply and generation of electricity.

1.6. As transmission licensee, National Grid is also required by its licence not to unduly discriminate between any persons or any class or classes of person or persons in discharging its functions.

Legal Framework for Decision

1.7. After receipt of the Final Amendment Report, the Authority makes a decision as to whether or not to direct implementation of the Amendment Proposal or any of the alternatives. It makes its decision in the context of a prescribed legal and assessment framework as set out below.

Impact assessment

1.8. Section 5A of the Utilities Act 2000 (Duty of the Authority to carry out an impact assessment) imposes a duty on the Authority to undertake an impact assessment in certain cases.

1.9. Section 5A of the Utilities Act 200 applies where:

(a) the Authority is proposing to do anything for the purposes of, or in connection with, the carrying out of any function exercisable under or by virtue of Part 1 of the Electricity Act or the Gas Act; and

(b) it appears to the Authority that the proposal is important within the meaning set out in section 5A, but does not apply where the urgency of the matter makes it impracticable or inappropriate for the Authority to comply with the requirements of section 5A.

1.10. Where section 5A applies, the Authority must either carry out and publish an impact assessment or publish a statement setting out its reasons for believing that it is unnecessary for it to undertake an impact assessment. An impact assessment must include an assessment of the likely effects on the environment of a proposal.

1.11. Section 5A(2) sets out the matters which would determine whether or not a proposal is “important” for the purposes of section 5A. These are where a proposal:

a. Involves a major change in the activities carried out by the Authority;

b. Has a significant impact on market participants in the gas or electricity sectors;

c. Has a significant impact upon persons engaged in commercial activities connected to the gas or electricity sectors;

d. Has a significant impact on the general public in GB or in a part of GB; and

e. Has significant effects on the environment.

Decision-making process

1.12. With regard to a CUSC amendment the Authority must assess the amendment proposal against the applicable CUSC objectives set out above. The Authority must also consider whether the proposal is compliant with its wider statutory duties, including those arising under European law. Further, the Authority must determine which of the options available to the Authority is best calculated to further the Authority's principle objective to protect the interests of consumers (including existing and future consumers) in relation to electricity conveyed, wherever appropriate by promoting effective competition.

1.13. A brief description of the Authority's powers and duties is set out at Appendix 3 of this document. Neither the above summary nor the summary at Appendix 3 is intended to be a substitute for referring to the relevant legal instrument.

Appendix 5 – Glossary

A

Access Rights

The rights to flow specified volume of electricity, usually from a specified location (node or zone) to an explicitly or implicitly defined destination (e.g. market hub), and for a defined period. For firm access rights, a failure to deliver access due to insufficient network capacity is associated with financial compensation. For non-firm access rights, the flow is terminated without compensation when capacity is unavailable.

The Authority/ Ofgem

Ofgem is the Office of the Gas and Electricity Markets, which supports the Gas and Electricity Markets Authority (GEMA), the body established by section 1 of the Utilities Act 2000 to regulate the gas and electricity markets in GB.

B

Balancing Mechanism (BM)

The mechanism for the making and acceptance of offers and bids pursuant to the arrangements contained in the BSC.

Bid

In the context of the Balancing Mechanism, a bid is a tool used by the GBSO, whereby a user submits data representing its willingness to reduce generation or increase demand. National Grid then decides whether or not to accept the bid.

British Electricity Trading and Transmission Arrangements (BETTA)

The arrangements for the trading and transmission of electricity across Great Britain which are provided for by Chapter 1 of Part 3 of the Energy Act 2004, which have replaced the separate trading and transmission arrangements which existed prior to 1 April 2005 in Scotland and in England and Wales.

Balancing Services Use of System Charges (BSUoS)

The charges levied by National Grid in respect of the activities it undertakes to keep the transmission system in electrical balance at all time.

C

Connection Entry Capacity (CEC)

A measure of the maximum capability, expressed in MW, of a connection site and the associated generation units' connection to the transmission system.

Connection and Use of System Code (CUSC)

Multi-party document creating contractual obligations among and between all users of the GB transmission system, parties connected to the GB transmission system and National Grid is relation to their connection to and use of the transmission system.

Consents

The process of obtaining Consents for the construction of a new overhead line to serve, for example, a wind farm can essentially be broken down into two distinct areas. Consents to be obtained from the Secretary of State/ Planning authorities etc in relation to permission allowing a line to be built and secondly, and more practically, consents from landowners who will be affected by the construction of the new line. For a new line consent under section 37 of the 1989 Act will be required.

In addition to section 37 consent, the DNO/TO must also obtain consent from the landowners over whose land the line will run. If a voluntary agreement cannot be struck, then either the land will have to be compulsorily purchased, under the provisions of section 10 and Schedule 3 (which is usually used for substations), or a Necessary Wayleave obtained over it, under the provisions of section 10 (Schedule 4 paragraphs 6-8).

Constraints

In the event that the pattern of generation may exceed the safe operational limits of a particular line or transmission system equipment, the GBSO will take actions to reduce the output of generators at specific locations on the system. At present these actions are taken in the Balancing Mechanism in the form of bids, and also via ancillary services, such as Pre-Gate Closure Balancing Mechanism Unit Transactions (PGBTs). Where a user's output is constrained down at a point on the system, the overall balance of energy will need to be retained, and costs will be incurred by the GBSO in bringing replacement energy onto the system.

Contracted background

This is the planning background against which National Grid assesses applications for connection and use of system. The contracted background includes all users that have entered into an (ongoing) agreement with National Grid for connection or use of system.

D

Deemed Transmission Entry Capacity (DTEC)

The deemed Transmission Entry Capacity allocated to certain generators under CAP148.

Deep reinforcement

Deep reinforcement refers to the works conducted on the wider transmission system in order to accommodate a change in the generation and demand pattern.

Directly Consequential Works (DCW)

The transmission works identified for a given generator which comprise local works required to connect a generator to the electricity grid.

G

GB System Operator (GBSO)

The entity responsible for operating the GB transmission system and for entering into contracts with those who want to connect to and/or use the GB transmission system. National Grid is the GB system operator.

GB Transmission System

The system of high voltage electric lines providing for the bulk transfer of electricity across Great Britain.

K

Kilowatt (kW)/Megawatt (MW)/Gigawatt (GW)

A kW is the standard unit of electricity, roughly equivalent to the power output of a one-bar electric fire. A MW is a thousand kilowatts. A GW is a thousand megawatts.

Kilowatt hour (kWh)/Megawatt hour (MWh)/Gigawatt hour (GWh)

One kilowatt hour is the amount of electricity expended by a one kilowatt watt load drawing power for one hour. A MWh is a thousand kilowatt hours. A GWh is a thousand megawatt hours.

L

Long-run marginal costs (LRMC)

In the context of electricity transmission, long-run marginal costs are the marginal costs of establishing and using network capacity. They include, for example, marginal costs for network reinforcement, as well as resulting network losses and residual congestion costs.

Local works

Those works required to provide a generator with a connection to the transmission network that would enable it to export power.

O

Offer

In the context of the Balancing Mechanism, an offer is a tool used by the GBSO, whereby a user submits data parameterising its willingness to increase generation or reduce demand. National Grid then decides whether or not to accept the offer.

S

Short-run marginal costs (SRMC)

In the context of electricity transmission, short-run marginal costs are the marginal costs of using established network capacity. They include, for example, network losses and congestion costs.

Short Term Transmission Entry Capacity (STTEC)

STTEC is a firm capacity provided, provided within-year, in 4, 5 or 6 week blocks.

T

Transmission Asset Owner (TO)

There are three separate transmission systems in Great Britain, owned by three Transmission Asset Owners, National Grid Electricity Transmission plc, Scottish Hydro Electric Transmission Ltd and Scottish Power Transmission Ltd. National Grid also has the role of system across the whole of Great Britain.

Transmission Entry Capacity (TEC)

The contracted maximum amount of electricity that each user is permitted to export on to the GB transmission system at any given time.

Transmission Network Use of System (TNUoS) charges

Charges that allow National Grid to recover the costs of providing and maintaining the assets that constitute the GB transmission system.

W

Wider Works (WW)

The transmission works identified for a given generator which comprise deep reinforcement works required to provide capacity to support the additional generation coming online.

Appendix 6 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

- Do you have any comments about the overall process, which was adopted for this consultation?
- Do you have any comments about the overall tone and content of the report?
- Was the report easy to read and understand, could it have been better written?
- To what extent did the report's conclusions provide a balanced view?
- To what extent did the report make reasoned recommendations for improvement?
- Please add any further comments?

1.2. Please send your comments to:

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