Title: **Proposals for improving grid access**	Impact Assessment (IA)
Lead department or agency: DECC	**IA No:** DECC 0008
Other departments or agencies:	**Date:** 27/07/2010
	Stage: Enactment
	Source of intervention: Domestic
	Type of measure: Other
	Contact for enquiries: Bernabé Sánchez, 0300 068 6317

Summary: Intervention and Options

What is the problem under consideration? Why is government intervention necessary?

Large amounts of renewable and other low-carbon generation capacity need to connect to our electricity networks to meet renewable energy and climate change targets. Timely connection of new capacity of all types is also essential if a sufficient margin is to be maintained to ensure continued energy security. Grid access arrangements have acted as a barrier to the connection of new renewable and other low-carbon electricity generation needed to meet the UK's climate change targets and ensure security of supply. The existing industry process was unable to deliver a solution in a timely manner. Parliament approved powers in the Energy Act 2008 to enable the Secretary of State to intervene, and a decision to intervene was announced in July 2009.

What are the policy objectives and the intended effects?

The objective is to introduce grid access reforms that help to deliver energy security and a clear path to delivering the UK's renewable energy targets. The intended effect is to provide sustained, commercially viable connection opportunities and firm connection dates reasonably consistent with project development timescales which will ensure the right environment for investment in new generation. The solution will need to be set in the context of protecting consumers, including minimising costs.

What policy options have been considered? Please justify preferred option (further details in Evidence Base)

A number of options were considered as part of the first consultation. The main difference between the different options is the allocation of network constraint costs that result from connecting new generators to the grid before full reinforcements have been completed. Based on responses to two consultations and the analysis commissioned for this impact assessment, Government's preferred option is Connect and Manage socialising constraint costs and two years user commitment. This model will provide a stable investment climate for new and existing generators, support the delivery of secure electricity and renewable targets, at little additional cost to consumers (just over 20 pence annually per household in our central scenario). The analysis suggests the preferred model is less complex and volatile and more predictable than the alternatives considered.

When will the policy be reviewed to establish its impact and the extent to which the policy objectives have been achieved?	It will be reviewed by the end of 2012
Are there arrangements in place that will allow a systematic collection of monitoring information for future policy review?	Yes

SELECT SIGNATORY Sign-off For enactment stage Impact Assessments:

I have read the Impact Assessment and I am satisfied that (a) it represents a fair and reasonable view of the expected costs, benefits and impact of the policy, and (b) the benefits justify the costs.

Signed by the responsible Minister: Charles Hendry ***Date: 27 July 2010***

Summary: Analysis and Evidence

Policy Option 1

Description:

Connect and Manage (C&M) Socialise

Price Base Year 2009	PV Base Year 2010	Time Period Years 11	Net Benefit (Present Value (PV)) (£m)		
			Low: - £160m	**High:** - £992m	**Best Estimate: - £195m**

COSTS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Cost** (Present Value)
Low			£20m	**£160m**
High			£122m	**£992m**
Best Estimate	£0m		£24m	**£195m**

Description and scale of key monetised costs by 'main affected groups'

Increased constraint costs occur due to increased generation capacity on the grid. These are estimated at £195m higher than I&C in NPV for the 2010-20 period, the equivalent of an increase of just over 20 pence per average annual household bill (5p per MWh). These costs are recovered by NG from generators and suppliers, who are assumed to pass the costs on to consumers in their entirety.

Other key non-monetised costs by 'main affected groups'

The additional ROC costs and network investment costs associated with meeting the renewable energy target are assessed and monetised in the RES Impact Assessment and are therefore not monetised in this impact assessment to avoid double-counting.

BENEFITS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Benefit** (Present Value)
Low	Optional		Optional	**Optional**
High	Optional		Optional	**Optional**
Best Estimate				

Description and scale of key monetised benefits by 'main affected groups'

Benefits associated with the RES leading scenario, including lower CO_2 emissions (12Mt CO_2 in 2020), lower wholesale prices (a saving of £955m in NPV for 2010-20) and a higher degree of security of supply as measured by the capacity margins are estimated. The benefits of these, however, are already included in the RES Impact Assessment and are therefore not monetised.

Other key non-monetised benefits by 'main affected groups'

There is an additional non-monetised benefit associated with the greater transparency and ease of implementation of this model. The complexity and unpredictability of other models is judged to increase uncertainty and investors' perceived risk.

Key assumptions/sensitivities/risks **Discount rate (%)** 3.5%

A range of scenarios were assessed, including different assumptions on fuel prices, the timeliness and delivery of required network investment, and different levels of renewable generation investment connecting to the grid in Scotland. The modelling assumes economic dispatch across the network and does not account for possible market power being exercised behind constrained boundaries, which was estimated to account for over half of constraints in 2008/09. Bid-offer spreads (which determine the price of constraints) are assumed to remain at historical levels.

Impact on admin burden (AB) (£m):			**Impact on policy cost savings (£m):**	**In scope**
New AB: £0m	**AB savings:** £0m	**Net:** £0m	**Policy cost savings:**	No

Enforcement, Implementation and Wider Impacts

What is the geographic coverage of the policy/option?			Great Britain			
From what date will the policy be implemented?			04/08/2010			
Which organisation(s) will enforce the policy?			Ofgem and Transmission Licensees			
What is the annual change in enforcement cost (£m)?			None			
Does enforcement comply with Hampton principles?			Yes			
Does implementation go beyond minimum EU requirements?			N/A			
What is the CO_2 equivalent change in greenhouse gas emissions? (Million tonnes CO_2 equivalent)			**Traded:** N/A		**Non-traded:** N/A	
Does the proposal have an impact on competition?			Yes			
What proportion (%) of Total PV costs/benefits is directly attributable to primary legislation, if applicable?			**Costs:** N/A		**Benefits:** N/A	
Annual cost (£m) per organisation (excl. Transition) (Constant Price)	**Micro**	**< 20**	**Small**	**Medium**	**Large**	
Are any of these organisations exempt?	No	No	No	No	No	

Specific Impact Tests: Checklist

Set out in the table below where information on any SITs undertaken as part of the analysis of the policy options can be found in the evidence base. For guidance on how to complete each test, double-click on the link for the guidance provided by the relevant department.

Please note this checklist is not intended to list each and every statutory consideration that departments should take into account when deciding which policy option to follow. It is the responsibility of departments to make sure that their duties are complied with.

Does your policy option/proposal have an impact on…?	Impact	Page ref within IA
Statutory equality duties[1] Statutory Equality Duties Impact Test guidance	No	22
Economic impacts		
Competition Competition Assessment Impact Test guidance	Yes	22
Small firms Small Firms Impact Test guidance	Yes	22
Environmental impacts		
Greenhouse gas assessment Greenhouse Gas Assessment Impact Test guidance	No	
Wider environmental issues Wider Environmental Issues Impact Test guidance	No	
Social impacts		
Health and well-being Health and Well-being Impact Test guidance	No	
Human rights Human Rights Impact Test guidance	No	
Justice system Justice Impact Test guidance	No	
Rural proofing Rural Proofing Impact Test guidance	No	
Sustainable development Sustainable Development Impact Test guidance	No	

[1] Race, disability and gender Impact assessments are statutory requirements for relevant policies. Equality statutory requirements will be expanded 2011, once the Equality Bill comes into force. Statutory equality duties part of the Equality Bill apply to GB only. The Toolkit provides advice on statutory equality duties for public authorities with a remit in Northern Ireland.

Evidence Base (for summary sheets) – Notes

Use this space to set out the relevant references, evidence, analysis and detailed narrative from which you have generated your policy options or proposal. Please fill in **References** section.

References

Include the links to relevant legislation and publications, such as public impact assessment of earlier stages (e.g. Consultation, Final, Enactment).

No.	Legislation or publication
1	Improving Grid Access Consultation Documents, Impact Assessments and Redpoint analysis: http://www.decc.gov.uk/en/content/cms/consultations/improving_grid/improving_grid.aspx
2	
3	
4	

+ Add another row

Evidence Base

Ensure that the information in this section provides clear evidence of the information provided in the summary pages of this form (recommended maximum of 30 pages). Complete the **Annual profile of monetised costs and benefits** (transition and recurring) below over the life of the preferred policy.

Annual profile of monetised costs and benefits* - (£m) constant prices

	Y_0	Y_1	Y_2	Y_3	Y_4	Y_5	Y_6	Y_7	Y_8	Y_9
Transition costs										
Annual recurring cost	0	0	0	3.9	32.7	34.5	11.3	32.4	42.4	68.6
Total annual costs	0	0	0	3.9	32.7	34.5	11.3	32.4	42.4	68.6
Transition benefits										
Annual recurring benefits										
Total annual benefits										

* For non-monetised benefits please see summary pages and main evidence base section

Evidence Base (for summary sheets)

A. Strategic Overview

The issue

The Government is committed to a European Union (EU) wide target of 20% of all energy to come from renewable sources by 2020. The UK's share is to achieve 15% of its energy needs from renewables. This could mean more than 30% of UK electricity generated from renewables by 2020.

If we are to meet the 15% target and the Government's commitment to reduce greenhouse gas emissions to at least 80% below 1990 levels by 2050, a significant proportion of our existing generation capacity will need to be replaced with new, lower carbon generation by 2020 and beyond. The UK will also need to connect other essential generation needed to replace the existing nuclear and fossil fuel plant that will close within the next decade. However, electricity generators - including new renewable energy generators – have faced significant delays in obtaining access to the transmission system.

Historically, the 'queue' for access has been managed on a "first come, first served" basis. As a consequence, less viable projects have, in many cases, blocked those that are further advanced or could be developed faster. It has been the case that capacity has been booked in the queue even when there is no realistic prospect of the project in question being connected by the contracted date. These arrangements have, therefore, led to considerable uncertainty and have acted as a barrier to entry into the energy market. This situation was, however, revised in May 2009 by Ofgem's adoption of an interim connect and manage approach. The key principle of Interim Connect and Manage is to facilitate the connection of generation ahead of the need for wider reinforcement works. This is delivered through derogations, granted by Ofgem, from the minimum standards in the National Electricity Transmission System Security and Quality of Supply Standard. This has already enabled the advancement of over 6GW of generation projects. However, Interim Connect and Manage is intended as a temporary solution pending the implementation of enduring transmission access arrangements.

Rationale for Government intervention

In the Transmission Access Review final report, the Government and Ofgem set out the need for fundamental reform to the long-term grid access rules in order to support the connection of the renewable and other low carbon generation that we will need by 2020 and beyond. In response, the industry developed options for reform of enduring access arrangements (see Section C below) which were submitted to Ofgem for consideration.

Parliament approved powers in the Energy Act 2008 to enable Secretary of State to intervene in this area, and a decision to intervene was announced in July 2009 in order to ensure that new generation is able to secure firm access dates in an appropriate timeframe, following recommendations from Ofgem and industry representatives. The view was taken that the industry process, whilst providing a valuable starting point, was unlikely to deliver a solution in a timely manner striking the right balance between the interests of new generators, existing generators and consumers. A failure of the existing process to achieve this was considered to represent a market failure due to lack of co-ordination.

Decision

The Government Response accompanying this Impact Assessment sets out the ***Government's decision to take forward a Connect and Manage socialised cost model with increased user commitment to two years***. This decision has been taken following two consultations and analysis carried out by Redpoint Energy. The following sections summarise the evidence base underpinning this decision.

B. Objectives

Grid access arrangements need to support the Government's climate change and energy security objectives including delivery of the UK share of the EU renewable energy target. Set in the context of protecting the interests of consumers, including minimising cost to consumers, our for new entrant grid access are to:

- provide sustained, commercially viable connection opportunities and firm connection dates reasonably consistent with project development timescales which will ensure the right environment for investment in new generation;
- deliver security of supply and a clear path to delivering our renewable energy targets;
- implement in a time-scale consistent with delivery of the Government's aspirations for 2020.

C. Identification of Potential Measures

Development of reform proposals
In order to achieve better use of the current network and accelerate access, industry working groups developed options for reform of the current access regime. This work was undertaken through the change management arrangements for the Connection and Use of System Code (CUSC) and National Grid's Charging Methodology Statement.

The CUSC is a multi-party contract that forms the basis of the legal framework for connection to, and use of, Great Britain's high voltage transmission system. The process for making amendments to the CUSC is governed by the CUSC Panel, which consists primarily of industry representatives. The CUSC Panel generally establishes working groups, made up of industry members, in order to assist with the assessment of amendment proposals. Ultimately, it is for Ofgem to decide whether any CUSC Amendment Proposal (known as a 'CAP') should be approved for implementation, although Ofgem is not able to propose amendments to the proposal before them. Ofgem makes its decision with reference to the Applicable CUSC Objectives, which relate to the facilitation of efficiency in electricity transmission and competition in generation and supply of electricity.

The industry process identified a number of potential options for reform of long-term access to the grid. These fell into two broad categories:

- 'Connect & Manage' options, whereby generators would receive a fixed connection date, and would be entitled to use the system from that date.
- Auctions (in one form or another), whereby any existing grid access arrangements would cease, in favour of reallocating all capacity by auction to all generators (both existing and new).

All industry reform proposals were submitted by March 2009 to Ofgem for consideration. A number of the reform proposals included variants. For example, for Connect and Manage, there were two alternative proposals: (i) a Socialised Cost model which would represent a minimum change model, removing the need to wait for wider transmission works and assuming a continuing socialisation of any resulting system operation costs (primarily the costs of resolving bottlenecks on the grid – constraint costs); (ii) a Targeted Cost model, which would target any constraint costs caused by the connection on accelerating new generators.

National Grid twice put forward a further proposal – a Capacity Pricing Mechanism (as CAP171 and then CAP172) – which was developed from one of the auction proposals (the Volume Auction). This proposal was not included in the industry process as, in the majority view of the industry CUSC Panel, it had substantially the same effect as proposals already under consideration.

Industry later discussed a further variant of Connect & Manage, although this was not worked up in detail. This could be based on the Socialised Cost model, but with new generators paying a proportion of the constraint costs caused and the remainder being recovered from generators on a locational and socialised basis. This represents a hybrid of the Connect and Manage Socialised and Targeted Cost models.

At DECC's request, KEMA Ltd considered modifications to the Connect & Manage Targeted Cost model so that it might better meet the DECC objectives, while mitigating costs. The model developed by KEMA – known as the Shared Cost & Commitment model – could include some or all of the following features:

- new users opting for a Connect & Manage connection can choose to accept a rolling 5 year liability to pay TNUoS[2] with a 5 year notice period or opt out of this commitment and have a 1 year liability for a share of forecast of incremental short-run constraint costs with a 5 day notice period
- these new users trigger investment in wider works and during the interim period ahead of the completion of wider works, are liable to pay a share of forecast of incremental short-run constraint costs arising as a result of Connect and Manage connection (in lieu of TNUoS)
- these new users pay (together with existing generators that opt out) a share reflecting 20% of forecast incremental constraint costs (with the relevant TNUoS charge setting a minimum for this), which is determined ex-ante for the entire interim period as part of their offer
- existing stations can choose to accept a rolling 5 year liability to pay TNUoS with a 5 year notice period or opt out of this commitment and have a 1 year liability for charges with a 5 day notice period
- existing generators that opt out (together with new users opting for a Connect & Manage connection) are liable (from the date of connection or the end of the notice period) for charges that reflect 20% of the forecast incremental constraint costs for the coming year (with the relevant TNUoS charge setting the minimum for this)
- the remaining 80% of forecast incremental constraint costs from each year (and any residuals from the ex-ante set charges) is recovered from all parties liable for TNUoS, potentially via a deferred recovery mechanism (which creates an annualised charge to recovers the costs over a 10 year period)

Other relevant developments

The effective management of constraint costs has been considered within the normal industry governance process. On 17 February 2009, Ofgem wrote to National Grid requesting that they undertake an urgent review of the existing commercial and charging arrangements. National Grid brought forward two urgent proposals: a CUSC amendment, CAP170: category 5 System-to-Generator Operational Intertripping Scheme; and a charging modification, GB-ECM-18; Locational BSUoS[3]. The first proposal, which has been submitted to Ofgem for decision, would extend administered prices for intertrip[4] arrangements to certain generators located behind derogated transmission boundaries. The second, which was vetoed by Ofgem[5] on 1 March 2010, would have introduced a locational element to BSUoS, effectively increasing costs

[2] Transmission Network Use of System charges, which are paid by generators and suppliers to cover the cost of building and maintaining the transmission network.
[3] Balancing Services Use of System charges, which are paid by generators and suppliers to cover the cost of balancing the network.
[4] An intertrip is a device that may be armed so that it automatically reduces output or temporarily disconnects a generator from the grid in certain circumstances, such as a fault on a specific part of the system. When an intertrip is in place, more energy can flow over the transmission system than would otherwise be the case, because the intertrip ensures that the system will be protected and will not be overloaded in the event of a fault
[5] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=137&refer=Networks/Trans/ElecTransPolicy/Charging

for generators behind an identified constraint. Currently, BSUoS charges do not vary by location.

The Energy Act 2010 provided for the introduction of a targeted Market Power Licence Condition which would give Ofgem the ability to address cases of undue exploitation of market power in the generation market. This would enable Ofgem to act in a situation where companies were taking advantage of insufficient electricity transmission capacity and unduly exploiting their regional market power to create excess profits at a cost to the consumer, and this could be identified.

DECC consultations

DECC published a first consultation document - 'Improving Grid Access' - in August 2009,[6] setting out the view that any reforms directed by the Secretary of State should be focused primarily on those changes needed to accelerate grid access for new generators. By taking this focused approach, DECC took the view that it should be possible to resolve a problem which had been under consideration through existing industry processes for some time.

This first consultation document presented an initial view that those models based on auctions or similar allocation mechanisms were not likely to be compatible with facilitating access to the grid for renewable energy and other new generation sources in a manner that would best protect consumers, ensure security of supply, assist in ensuring a sustainable development and meet our climate change targets. These models were considered likely to lead to disruption across existing generators as well as future generators. DECC considered that these models did not appear to be proportionate and targeted at facilitating access to the transmission system.

The consultation document set out a preliminary view that models based on 'Connect and Manage' were likely to best meet the objectives set out in Section B of this Impact Assessment. A model which built on current arrangements and effectively balanced the interests of new entrants, existing generators and consumers was considered to be the best way forward.

In the consultation document we sought views on three potential Connect & Manage models:

- Connect and Manage (Socialised): A model that fully socialises any additional constraint costs. Under these arrangements costs will be shared between all users of the network and ultimately consumers.
- Connect and Manage (Hybrid): A model that targets some, but not all, of the additional constraint costs on new entrant power stations. These costs may be limited because of the incentive for new entrants to reduce their impact on overall costs through their choice of location and operation profile.
- Connect and Manage (Shared Cost and Commitment): A model that requires new and existing power stations to commit to the network in return for greater certainty over charges, or to opt out and be exposed to additional constraint costs.

The Connect and Manage Targeted Cost model was not included as an option for consultation. Analysis of the costs of this model by National Grid suggested that the BSUoS charges faced by a new renewable generator in North Scotland could be around £55/MW/hr under a Targeted Cost Model (compared to less than £10/MW/hr for comparable existing generators). These costs would clearly have a negative impact on new renewable deployments and on our ability to meet our objectives[7]. Our initial view was therefore that this model would prevent new renewables investment in key locations and would not meet our objectives of delivering a clear path to delivering our renewable energy targets and meeting our aspirations for 2020.

[6] See http://www.decc.gov.uk/en/content/cms/consultations/improving_grid/improving_grid.aspx
[7] See National Grid presentation, 'Comparison of charges under different models of access reform', http://www.nationalgrid.com/NR/rdonlyres/C524A352-8E4B-4377-B2C0-3803C5C0E497/34820/AccessChargingComparison_TCMF.pdf

A Partial Impact Assessment was published alongside the first consultation. This included a preliminary analysis of costs and benefits associated with the Connect and Manage approaches. This initial assessment considered that additional constraint costs for the Connect & Manage socialised model over and above a 'do nothing' scenario would have a net present value of approximately £633 million between 2009-2020. This equated to an average cost per year of approximately £61.5 million. It was considered that costs for the Hybrid and Shared Cost & Commitment models would be somewhat lower. However, it was noted that, before any final decision was reached, we would undertake more detailed analysis including a quantitative assessment of the differences in constraint costs expected between the three potential models identified in the consultation document. This led to new analysis being commissioned from Redpoint Energy.

Other changes to the framework were considered during the industry process and it was noted that these could also have benefits for the development of the overall access framework. These included the changes to the amount of 'user commitment' which all existing and new generators must give to remain on the network. Currently, all plants must give one financial year's notice before reducing the amount of network capacity they need. At the end of the financial year, this can mean only five days notice.

A second consultation was undertaken between March-April 2010 on the detail of our preferred approach – a Connect and Manage socialised cost model – as well as the code and licence changes to implement it. Alongside this, an updated version of the Impact Assessment was published which incorporated results of the analysis undertaken by Redpoint Energy. These results are summarised in Sections E and F below.

D. Analytical Background

The trade-off

The economic background to this intervention is that there is a trade-off between efficiency, regulatory and network charging complexity and the delivery of the Government's 2020 renewable energy targets (and progress towards the full decarbonisation of the electricity sector over a longer timescale). The demands placed on the transmission network in order to connect the 71GW of new generation capacity seeking access (almost the same capacity as currently connected) require substantial investment.

This impact assessment is not concerned with the overall costs of this transmission investment, which are the subject of other studies (e.g. the ENSG analysis referred to below and further work undertaken since by Ofgem)[8], and which are costs that are already included in the impact assessment for the July 2009 Renewable Energy Strategy. Instead, it is concerned with the trade-off between connecting new generators only when the network is ready to accommodate them (the old Invest then Connect (I&C) grid access regime) and connecting them earlier under a C&M grid access regime. The trade-off is one between the speed with which new generators are connected (which will have a knock-on impact on renewable targets, security of supply and wholesale prices) and the level of congestion that can be expected in the network, which has a set of costs associated with it generally referred to as constraint costs.

Constraint costs: the background

Constraint costs arise as a result of the need to balance power flows across the transmission network. A generator might have contracted to deliver a supplier elsewhere in the network with a certain volume of electricity, but at the time it attempts to dispatch that volume the network might not be able to transport that power. National Grid, in its role as the National Electricity Transmission System Operator (SO) then has to ask the generator to reduce its output (at a price) whilst at the same time ensuring the supplier receives the power from another generator

[8] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=204&refer=Networks/Trans/ElecTransPolicy/tar

(who must also be compensated) elsewhere in the network. The SO can achieve this through the Balancing Mechanism (BM), which relies on decisions taken in the half hour before dispatch is required and is therefore more costly, or through contracts or trades negotiated further in advance. The latter can be a more attractive option when certain parts of the network are expected to be constrained, because of planned outages in the network (e.g. for maintenance during the summer) or because of a lack of transmission capacity relative to generation capacity in certain parts of the network (the clearest example of this at the moment is Scotland).

Constraint costs are important to the analysis that follows for two main reasons: (1) increased constraints are the main cost associated with the accelerated access to the network made possible by the C&M arrangements; and (2) the way these constraint costs are estimated and allocated represents the main difference between the different C&M models considered.

Network investment and the ENSG Vision for 2020

Two previous policy processes set the context and background for this piece of analytical work. The long-term solution to network congestion and constraints is investment to expand network capability. In March 2009 the Electricity Networks Strategy Group - a cross-industry group jointly chaired by DECC and Ofgem - produced a report recommending[9] network reinforcements of £4.7 billion which could accommodate a further 45GW of generation, including 34GW of onshore and offshore wind generation necessary to meet our 2020 targets. The report noted that the circuits between Scotland and England are already operating at their maximum capability, and identified a number of upgrades from the North of Scotland to the Central Belt, and on to the North of England. The extent of these upgrades is dependent on the level of renewable investment in Scotland under the different scenarios analysed. The analysis carried out by Redpoint for this Impact Assessment builds on the ENSG work and the assumptions about network investment are consistent with the ENSG recommendations.

It is worth noting that the ENSG report set out, at a strategic level, recommendations for reinforcements that need to be made on an anticipatory, pre-emptive basis, to accommodate future generation to 2020. The pre-emptive reinforcements identified are required because they are likely to take longer to deliver than the generation projects whose electricity they will transport. Other potential reinforcements were excluded from the report where the transmission owners judged that it would be able to deliver them within the required project development timescales.

Network charges

An area of concern that has been raised from an economic efficiency perspective is that some of the options being assessed (and particularly the Government's preferred option) do not provide the right incentives for efficient network location decisions to be made by new generators. However, it has also been argued that the signals and incentives for efficient investment decisions are already provided by the locational element in the Transmission Network Use of System (TNUoS) charges for generators.

Thus, based on National Grid's proposals for 2010/11[10] a 1.5GW generator located in the North of Scotland will pay about £30 million whereas a comparable generator based in South West England would receive £7 million. Figure 1, summarising TNUoS charges for a few selected network zones over the past five years, illustrates these locational incentives.
TNUoS charges are one of two network-related charges levied on electricity generators and suppliers. TNUoS charges totalled £1.4 billion in 2008/09,[11] paid for by suppliers (73% of the total) and generators (27%). The other charge is Balancing Services Use of System (BSUoS),

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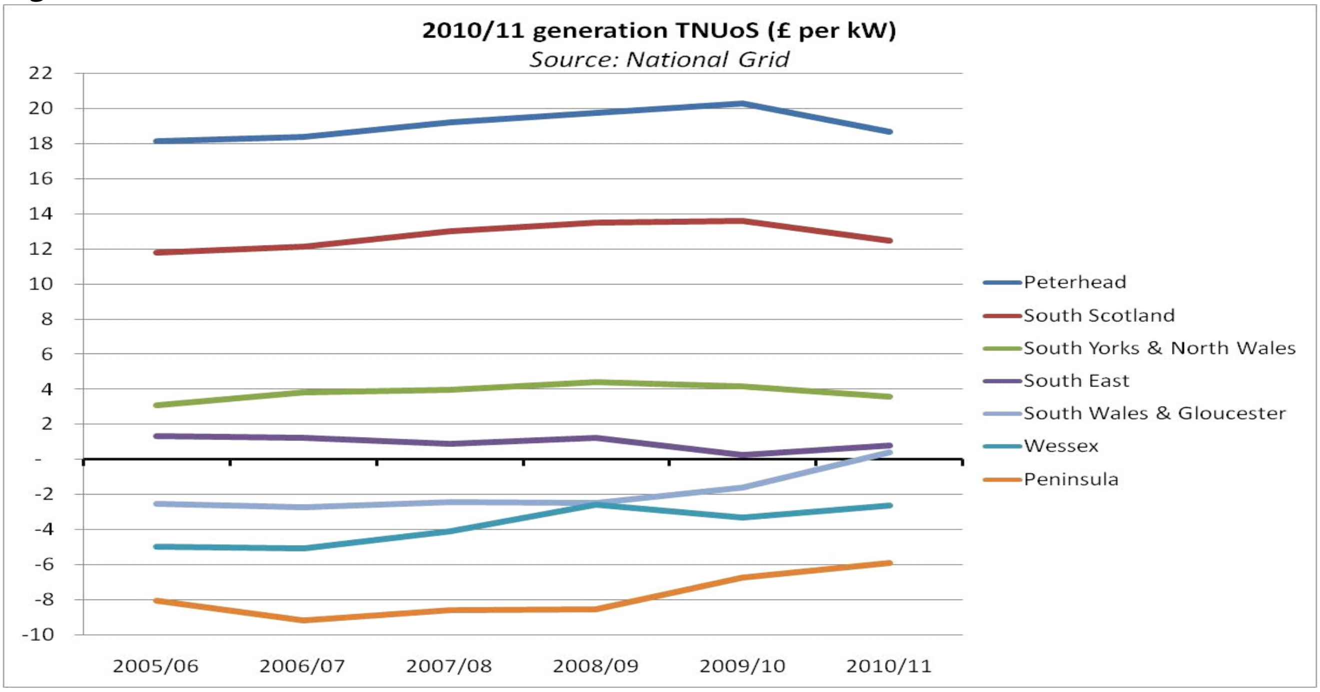
[9] ENSG (2010): *Our Electricity Networks: A Vision for 2020*
http://www.ensg.gov.uk/assets/ensg_transmission_pwg_full_report_final_issue_1.pdf
[10] http://www.nationalgrid.com/NR/rdonlyres/9D3D4ACC-A26A-49B4-A36D-D20912890F64/39114/DraftTNUoStariffsfor2010.pdf
[11] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=41&refer=Networks/Trans/RegReporting

which totalled £1 billion in 2008/09 and is shared equally by suppliers and generators. Constraint costs are currently recovered through BSUoS.

Figure 1



Thus, a 1.5GW generator located in the North of Scotland using gas as its fuel and running at a load factor of 58% in 2010/11 is expected to face total transmission charges (TNUoS and BSUoS) of £40 million, compared to just £3 million for the comparable generator based in South West England. To put this into context at current market prices the margin between the cost of natural gas and electricity is about £7 per MWh, suggesting a margin excluding operational costs and transmission charges of £53 million (assuming a load factor of 58%).

Market power

A parallel process that informed the background to this impact assessment was the inclusion of a Market Power Licence Condition (MPLC) in the Energy Act 2010. In the event of a relatively small area of the network being constrained there is a potential opportunity for generators behind that constraint to exercise market power through uncompetitive pricing of their bids and uneconomic dispatch. In broad terms generators may be in a position to run their plant at higher load factors and submit uncompetitively low bids in the knowledge that they are likely to be asked by the SO to reduce their output volume and be compensated accordingly. A third of the Energy Act 2010 Impact Assessment[12] was devoted to the MPLC. The analysis estimated that over half of the £238m cost of constraints in 2008/09 had been due to market power being exercised in Scotland.

Redpoint's modelling is based on economic dispatch decisions so it implicitly assumes market power is not exercised anywhere in the network – an assumption that should be consistent with the successful application of measures such as the MPLC.

Differences between Redpoint's results and other analyses of constraints

Three other pieces of analysis have informed the analysis underpinning this impact assessment. The first is the analysis prepared by National Grid in relation to their locational BSUoS proposal.[13] Redpoint build on National Grid's approach in order to model the constraint cost savings associated with one of the access models (C&M with locational BSUoS).

[12] http://www.decc.gov.uk/media/viewfile.ashx?filepath=legislation/energybill/1_20091119144019_e_@@_energybillimpactassess.pdf&filetype=4

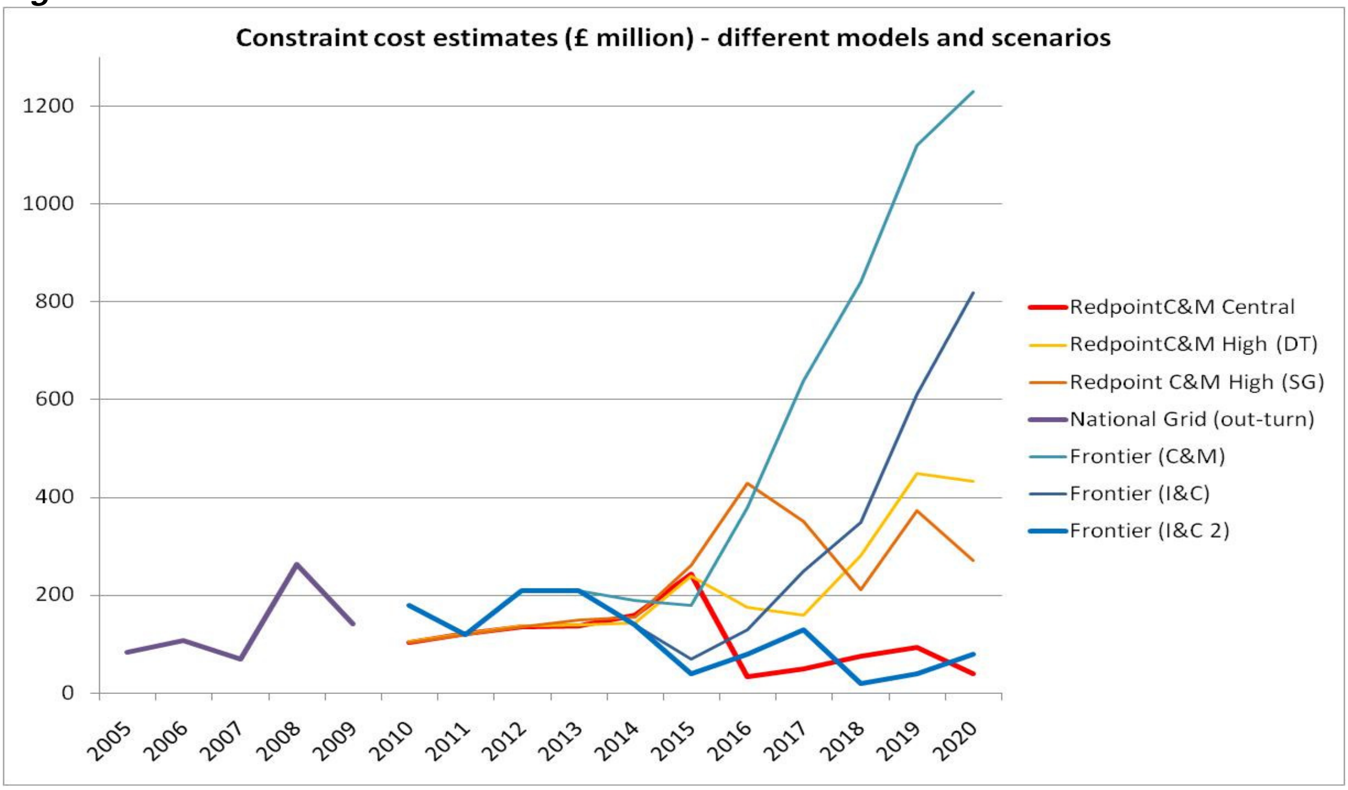
[13] http://www.nationalgrid.com/NR/rdonlyres/CF064BAF-E8AB-412F-A06B-AD52AE737F35/38612/AddendumtoLocBSUoS_cleandated26Nov2009.pdf

The second new piece of analysis that has informed this impact assessment is the work Frontier Economics carried out to inform Ofgem's response to the consultation.[14] This analysis highlighted the concern that higher generation investment in Scotland combined with underinvestment in the network would lead to exponential increases in constraints. An assessment of the difference between the Redpoint and the Frontier results was undertaken and included in the Redpoint report. The drivers of the differences were found to be the level of investment assumed for the network (particularly for the North of Scotland) and the amount of wind capacity connecting to the grid in Scotland. DECC's view is that on both these areas Frontier's scenarios are very unlikely.

However, in order to address these concerns a fourth scenario was developed by Redpoint with pessimistic assumptions on network investment in Scotland combined with what a variety of studies perceive to be the highest feasible level of renewable generation that might connect to the grid in Scotland by 2020. These results are reported in the sensitivity analysis section below.

The further piece of relevant analysis is the latest National Grid forecast[15] for 2010/11 constraints. National Grid's estimates for this year are much higher than Redpoint's. These differences have been discussed and assessed with National Grid and Ofgem. Redpoint's approach to modelling the merit order between different technologies and specific power stations takes better account of market fundamentals than that taken in National Grid's forecasts and is not driven so much by historical patterns. It therefore better reflects a scenario where economic dispatch takes place (as implied by the application of measures such as the MPLC described above). Further information is set out in Annex 2. DECC's conclusion is that Redpoint's results are a fair and independent reflection of what is likely to happen in a world where generation is driven by economic dispatch of electricity.

Figure 2



[14] http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/Frontier_CM_Constraints.pdf
[15] For a breakdown of forecast and actual constraint costs since BETTA, see:
http://www.nationalgrid.com/NR/rdonlyres/1B6B81A0-7583-4EC0-B16D-A814E2100546/38603/ElectricitySOIncentivesHistoricForecastCosts.pdf
The final forecast for 2010/11 is available in Ofgem's final SO Incentives proposals:
http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/SO%20Final%20Proposals%20Consultation%20Document_elec%20only.pdf

Constraint cost estimates in the partial impact assessment published with our first consultation relied on National Grid's model. The same conclusion therefore applies to the difference between Redpoint's estimates of the impact of our different policy options and the estimates contained in the partial impact assessment.

Finally, Ofgem published its derogation decision on the first tranche of projects to advance under the Interim Connect and Manage regime in July 2010. This took into account analysis of costs and benefits undertaken by National Grid using the same suite of models and therefore our conclusion that Redpoint provides a fair and independent assessment of future constraints remains valid.

The difference between the Frontier and Redpoint estimates, National Grid's short-term forecast and historical data is illustrated in Figure 2, taken from Redpoint's assessment of the differences.

E. Redpoint Analysis: approach and models assessed

Redpoint Energy carried out the analysis[16] underpinning this impact assessment. The aim of the analysis was to establish the impact of the different access regimes in the consultation on constraint costs, progress towards renewable targets, security of supply and wholesale prices. Establishing these impacts required modelling the interactions between existing generators' electricity dispatch behaviour and investment in new generation. To do this Redpoint used their Investment Decision Model (IDM) to simulate the 'real world' investment dynamics in the electricity sector and a Plexos model (configured to represent a simplified zonal model of the GB transmission network) to model the outturn operation of the market.

Table 1 – Grid access models assessed

Access Regime	Key Features
Base Case – Invest then Connect	As per historic regime – all generators begin exporting at completion of wider works. No targeting of constraint costs
Base Case – Connect and Manage Socialised	Generators may begin exporting at completion of enabling works Incremental constraint costs socialised across all users
Connect and Manage – Hybrid	New generators may begin exporting at completion of enabling works A proportion (50%) of ex-ante forecast of incremental constraint costs targeted on new generators during the period between completion of local and wider works. Remainder of constraint costs socialised across all users
Connect and Manage – Locational BSUoS	New generators may begin exporting at completion of enabling works Generators situated behind a derogated transmission boundary pay locational BSUoS based on an ex-post calculation of the proportion of constraint costs attributable to non-compliance. Remaining constraint costs socialised across all users
Connect and Manage – Shared Cost and Commitment	New generators may begin exporting at completion of enabling works Existing generators given an annual choice to 'opt-in' or 'opt-out' of a rolling 5-year user commitment New accelerating generators and 'opt-out' generators pay an Accelerated Access Charge (AAC) (20% of ex-ante forecast of incremental constraint costs), with a one-year commitment period 'Opt-in' generators pay a Deferred Recovery Charge (DRC) based on ex-post reconciliation of incremental constraint costs, logged up and recovered over 10 years

[16] http://www.decc.gov.uk/Media/viewfile.ashx?FilePath=Consultations\Improving Grid Access\1_20100114135618_e_@@_improvinggridaccessredpointfinal.pdf&filetype=4

Redpoint assessed the access models outlined in the consultation document as the main policy options. These are summarised in Table 1 below, and included Invest then Connect (I&C), which is used as our ‘do nothing’ or counterfactual model, and a number of Connect and Manage (C&M) policy variants.

The main difference between the C&M variants is the way in which constraint costs arising from C&M are allocated. Under the C&M socialised model all incremental constraints from accelerating access are socialised across all network users. This is effectively a continuation of Interim C&M on an enduring basis. The C&M hybrid option considered in this impact assessment is one in which new generators would be liable for 50% of the incremental constraint costs due to their acceleration. C&M locational BSUoS, an alternative form of hybrid, applies the locational BSUoS methodology proposed by National Grid as the way of allocating constraint costs across all generators behind a boundary deemed not to be compliant with the required standards. C&M Shared Cost and Commitment (SCC) targets 20% of forecast increases in constraint costs to new generators (and generators opting out of the access regime), with 80% being socialised. The SCC model also includes some other variations, such as reducing the volatility of charges, deferring their recovery of those charges over ten years and increasing user commitment.

The impacts of these models were assessed across a range of different scenarios. Different assumptions were tested on the level of investment and capability of the network, fuel prices, level of renewable investment in Scotland and generators’ dispatch behaviour (in the case of C&M locational BSUoS). Table 2 summarises the four scenarios used.

Table 2 – Key Scenario drivers

Scenario driver	Low	Central	High DT (Delayed Transmission)	High SG (Scottish Generation)
Transmission reinforcement	ENSG Baseline • Onshore 2015 • Western DC 2015 • North Scotland II 2018		Delayed Reinforcement • Onshore 2020 • Western DC 2025	Delayed Reinforcement • Onshore 2017 • Western DC 2017 • Eastern DC 2020 • North Scotland II 2020
Fuel prices	Gas favouring (DECC Central with a lower gas price)	DECC Central		
Scottish wind build	Central build rates			Stretch build rates
Scottish thermal plant	Longannet and Peterhead operate under IED restricted hours derogations from 2016			Longannet and Peterhead operate unrestricted by IED

F. Summary of costs and benefits: central scenario

Table 3 below summarises the results for the five models assessed for the central scenario. The key result is that under I&C the UK would be unable to achieve the RES leading scenario (which requires 29% of electricity to be delivered from renewable sources). All C&M models would enable the delivery of the RES leading scenario, albeit at a cost of additional constraints.

The level of additional constraints, however, is so small (£195m over 2010-20 in NPV terms[17]) that the different C&M models deliver effectively the same level of renewable investment over the period. The only difference between the C&M models is that C&M locational BSUoS would deliver a constraint cost saving (of £103m over the same period in NPV[18]) if existing conventional generators were able to forecast constraint costs and alter their dispatch behaviour. That saving is partly offset by an increase in wholesale prices, as generators factor the locational BSUoS charge into their short-run marginal costs and pass the cost to consumers.

Table 3 – Access models' impacts – central case scenario

	I&C	C&M socialised	C&M hybrid (50%)	C&M loc BSUoS	Shared Cost & Commit
RES-E 2020 – % electricity from renewable sources	23.2%	30.5%	30.5%	30.5%	30.5%
CO2 emissions from power sector in 2020	131.9Mt	119.7Mt	119.7Mt	119.7Mt	119.7Mt
RES capacity 2020 (GB)	24.2GW	32.9GW	32.9GW	32.9GW	32.9GW
of which wind	18.3GW	26.8GW	26.8GW	26.8GW	26.8GW
RES capacity 2020 (Scotland)	8.8GW	11.2GW	11.2GW	11.2GW	11.2GW
of which wind	6.2GW	8.3GW	8.3GW	8.3GW	8.3GW
Constraint costs - 2010-20 NPV	£804m	£999m	£999m	£896m	£999m
Increase in constraint costs from I&C		**£195m**	**£195m**	**£92m**	**£195m**
Wholesale price saving relative to I&C, 2010-20 NPV (net of increased cost of balancing)		£955m	£955m	£899m	£955m

It is worth noting that the incremental constraint costs associated with the C&M models assessed are forecast to be much lower than were previously expected. They are the equivalent of £18m per year, which translates into an increase of just over 20 pence in an average household's annual electricity bill.

DECC's view is that the analysis also highlighted the complexity of implementation and monitoring arrangements associated with the non-socialised C&M models. The sensitivity analysis in section G below also suggests that the non-socialised C&M models would lead to unpredictable and highly volatile charges in specific parts of the network under certain scenarios. ***These factors (complexity, unpredictability and volatility) would in DECC's view increase the perceived risk to investors and has the potential to deter investment in generation***.

DECC's conclusion is that these risks, although difficult to quantify, outweigh the relatively small costs associated with the C&M socialised model, and therefore form the basis of our recommendation. The following sections summarise in more detail the costs and benefits associated with each access model assessed.

[17] NPV calculated consistently throughout for the period 2010-20; 3.5% discount rate used as suggested in HM Treasury's Green Book guidance.
[18] This is calculated as the mid-point in the range estimated by Redpoint in their analysis.

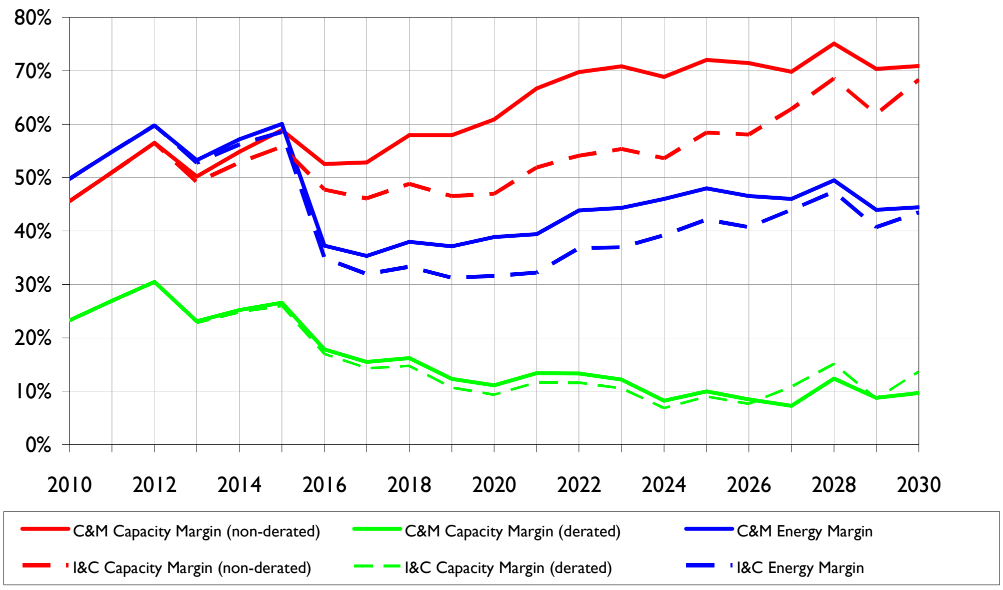
(i) Invest then Connect ('do nothing' model – counterfactual)
The main monetised benefit associated with this model is the avoidance of an estimated £18m of annual constraint costs associated with the connection of new generators before wider works to accommodate them on the network are completed.

The main cost is that the UK would fail to achieve the RES lead scenario, with only 23% of electricity generated from renewable sources by 2020 (rather than the 29% required). The renewable energy targets would then have to be met by a greater effort from the other sectors considered in the RES (namely transport, heat and small-scale generation). There is also a cost in terms of higher CO2 emissions incurred as a result of not meeting the target, as well as higher wholesale prices. A final cost associated with not meeting the RES targets is a reduction in security of supply in the GB electricity sector, as illustrated by the capacity margin trends in Figure 3 below.

Falling short of the large scale renewable electricity output required to meet the RES leading scenario has some associated quantifiable benefits, such as lower ROC costs and potentially lower investment in the network required. A scenario with only 24% large scale electricity generation was assessed in the RES impact assessment. Although it was found to be cheaper than the lead scenario (at a net benefit of -£52 billion in NPV to 2030 as opposed to -£56 billion in NPV to 2030), the balance of risks led the Government to conclude that the more expensive scenario requiring greater large scale renewable electricity generation was the lead scenario.

This impact assessment does not attempt to monetise any of the costs and benefits associated with the different RES scenarios, which are already covered in the Overall Impact Assessment of the RES.[19]

Figure 3 – Impact of C&M on security of supply – Capacity Margins



(ii) C&M with socialisation of incremental constraint costs (C&M socialised)
The main benefit of the C&M socialised model is that by offering a timely connection date to new investors it helps deliver the RES targets. Meeting the RES targets has the associated benefits of lower CO2 emissions, lower wholesale prices and higher security of supply margins. As above these benefits are already counted in the RES impact assessment and are therefore not monetised in this impact assessment. The same is the case for the incremental cost of network infrastructure and ROC costs, which again was included in the RES impact assessment and is therefore not monetised.

[19] http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/res/res.aspx

The key monetised costs of the C&M socialised are the incremental constraint costs that it causes in the network. These costs are £195m in NPV terms over 2010-20, working out at £18m per annum. The assumption is that generators and suppliers pass on the entirety of these costs to consumers, increasing an average household's annual electricity bill by just over 20 pence.

Other non-monetised benefits associated with this option are the transparency and simplicity of its implementation. It would in effect represent a continuation of the current interim measures. Industry responses to the consultation have also been largely supportive of this model.

(iii) C&M with targeting of 50% of incremental constraints costs (C&M hybrid)
Redpoint's modelling shows that beyond Combined Cycle Gas Turbine power stations (CCGTs) already under construction and investment in renewable generation driven by the RO, there is not a strong enough incentive for further investment in electricity generation over the next decade. The only way that C&M hybrid can therefore have a different impact to C&M socialised is if the targeting of incremental constraint costs leads to lower investment levels in renewable generation.

Redpoint carried out a 'tipping point' calculation to estimate the level of charge that would lead to a renewable generation investor deciding not to accelerate their access to the grid. The calculation varies depending on the location of the investment and the expected load factor, but for the average onshore Scottish wind investment the charge would have to be as high as £25 per MWh to dissuade the investor from connecting to the grid. The maximum estimated charge with 50% targeting would be just over £10 per MWh for generators in the northernmost zone of Scotland in 2013. Given the low level of constraints estimated over the period, Redpoint conclude that the same renewable capacity would be delivered as with the C&M socialised model, and therefore the benefits and costs are exactly the same as described above.

There are three more qualitative differences. The first is that as 50% of the additional costs would be borne by generators with a short-run marginal cost of zero (or even negative) the cost might be absorbed by those generators, representing a transfer of the cost burden from consumers (who would be better off) to the wind generators (who would be worse off). Whereas the costs and benefits would be the same as under C&M socialised, the distributional impacts would not.

A second complication would be identifying the level of constraint costs that are due to C&M as opposed to other reasons such as delays in network investment or possible market power. Whereas this is relatively straight-forward in a modelling exercise assuming economic dispatch (such as the one carried out by Redpoint), real life is inevitably more complicated. As a result any proposed methodology to attribute costs after the event would be subject to challenge and increase perceived uncertainty and risk.

Finally, there would be an unquantifiable effect on investor confidence in the UK due to an additional charge being imposed on new generation.

(iv) C&M with constraint costs targeted using National Grid's locational BSUoS methodology (C&M locational BSUoS)
Redpoint modelled the impact of applying the National Grid methodology for allocating constraint costs to generators behind constrained boundaries. The result in the central scenario is that charges would peak at about £4 per MWh of energy generated in the northernmost zone of Scotland in 2013. Estimated charges in all other years and zones are estimated to be significantly lower. Using their 'tipping point' calculation Redpoint conclude that the expected charges are therefore not high enough to disincentivise investment in new renewable generation, so non-monetised costs and benefits associated with the RES targets are again the same as for C&M socialised.

Because the locational BSUoS charges apply to all generators, Redpoint find that there would be an impact on conventional generators' dispatch behaviour. Faced with the charges, owners of flexible plant have the opportunity to reduce their output in anticipation of particularly windy periods of time in order to avoid the charge. The precise behaviour of these generators is difficult to judge, so in line with the methodology developed by National Grid, Redpoint present a range of constraint costs given by two extremes: (1) where all generators can fully anticipate the charge and fully adjust their behaviour accordingly; and (2) where generators do not have the ability to anticipate when charges will apply and therefore simply adjust their SRMC to take into account these increased costs.

The impact of locational BSUoS therefore depends on generators' ability to accurately anticipate periods of time during which the network will be constrained. Given the fact that they only become aware of what their BSUoS charge for each half hour slot is two days after they have been incurred, feedback from the industry has been sceptical about generators' capacity to adequately adjust their behaviour. Table 3 above presents the mid-point in the range estimated by Redpoint. The result is that constraint costs are expected to increase relative to I&C by less than half the amount (£92m in NPV over 2010-20) estimated for C&M socialised. Interestingly, however, wholesale prices would be expected to be slightly higher than under C&M socialised, as generators factor in anticipated charges into their SRMCs. This effect would reduce the difference between the two options to less than £50m in NPV over the 2010-20 period, the equivalent of just over 6 pence annually per household.

There would also be an unquantifiable effect on investor confidence in the UK due to a new, complex and unpredictable ex post charge being imposed on generation in certain parts of the network. As more boundaries are expected to be derogated, the charge would apply in different parts of the network and become more difficult to predict.

(v) C&M Shared Cost and Commitment (SCC)

The SCC model targets 20% of non-compliant constraint costs on new generators choosing to accelerate their access and socialises the remaining 80%. Therefore, at the low levels of constraints expected in the central scenario, the impacts of the model would be the same as they are for the C&M socialised and hybrid models.

There could potentially be some unquantifiable benefits from some of the model's other features. The ability to fix the amount charged for constraint costs would increase predictability and deferring the recovery of the socialised costs could reduce the costs to existing generators. However, at the low levels of constraints expected in the central scenario these impacts would not be material.

There would be an unquantifiable risk from the complexity of the model and the potential impact on investor confidence in the UK market.

A useful feature of the SCC model is the requirement for more network user commitment on the part of generators. This additional level of user commitment would potentially produce two benefits:

- assist the Transmission Owners in planning new investment in the network, and hence reduce the risk of inefficient investment;
- enable the Transmission Owners and Ofgem to better justify investment in the network, so helping to ensure that critical network investment goes ahead, and thereby facilitating Government targets as well as the reduction of constraint costs in the longer term.

We consider that increased user commitment is therefore a useful proposal in its own right.

User commitment
We are increasing the user commitment which all generators give to the network from the current one financial year to two financial years.

In line with views expressed by some consultation respondents, our change to user commitment is designed to help support efficient use of the transmission system by helping the System Operator and Transmission Owners to plan strategic network investment. It will also contribute towards the ultimate solution to constraint costs – as Redpoint's analysis shows, constraint costs rise most when transmission investment lags behind generation investment.

Responses to both our consultations suggest that this level of user commitment would not have unintended adverse impacts on security of supply. We are not increasing beyond two years because we do not have the evidence to show what the effect of this might be on existing generators and therefore on security of supply. We have however indicated that industry and Ofgem should keep under review whether further changes to user commitment would be appropriate.

G. Sensitivity analysis

As noted above, Redpoint's central scenario provides significantly lower estimates of constraint costs than other recent analyses. It was therefore important to carry out sensitivity analysis around some of the key drivers of constraints. Initially this was understood to mean different levels of network investment and different fuel prices. This led to the development and assessment of the high constraint cost scenario DT (delayed transmission) and the low constraint cost scenario where lower gas prices relative to coal lead to higher levels of generation in the less congested south of England, thereby reducing costs. Following the publication of Frontier's analysis it became clear that some sensitivity testing on the levels of generation in Scotland was also necessary.

Table 4 – Impact of C&M under different scenarios

	Invest then Connect (I&C)				Connect and Manage (C&M)			
	High SG	High DT	Central	Low	High SG	High DT	Central	Low
RES-E 2020	23.2%	22.8%	23.2%	21.8%	30.7%	30.5%	30.5%	30.5%
CO_2 2020	136.7Mt	132.8Mt	131.9Mt	121.2Mt	123.8Mt	121.0Mt	119.7Mt	107.9Mt
RES capacity 2020 (GB) *Of which wind:*	24.2GW *18.3GW*	23.6GW *17.8GW*	24.2GW *18.3GW*	24.1GW *18.3GW*	33.2GW *27.0GW*	32.9GW *26.8GW*	32.9GW *26.8GW*	32.9GW *26.8GW*
RES capacity 2020 (Scotland) *Of which wind:*	8.8GW *6.2GW*	8.3GW *5.7GW*	8.8GW *6.2GW*	8.8GW *6.2GW*	14.4GW *11.5GW*	11.2GW *8.3GW*	11.2GW *8.3GW*	11.2GW *8.3GW*
Constraint costs – 2010-20, NPV	£1,027m	£1,021m	£804m	£411m	£2,019m	£1,849m	£999m	£571m
Incremental constraint costs due to C&M – 2010-20, NPV	n/a	n/a	n/a	n/a	£992m	£827m	£195m	£160m
Wholesale price fall (net of increase balancing cost) due to C&M – 2010-20, NPV	n/a	n/a	n/a	n/a	£994m	£993m	£955m	£106m

The results of this testing for I&C and C&M socialised are summarised in Table 4. The main messages are that under all scenarios C&M would enable the delivery of over 30% of electricity from renewable sources. Moreover, even under the high constraint cost scenario assuming the maximum feasible wind deployment in Scotland and pessimistic two-year delays in network investment (SG), incremental constraints are just under £1 billion over 11 years. This is the equivalent of an increase of just over £1 per average annual household electricity bill.

As discussed above, for the C&M locational BSUoS access regime the modelling also tested the sensitivity of the results to the behavioural response and forecasting ability of generators. This gives the range of costs summarised in Table 5. Under all assumptions (perfect and imperfect anticipation by generators, central scenario or high SG scenario), locational BSUoS delivers lower constraint costs than C&M socialised. However, in these four scenarios about half of the saving in constraint costs from locational BSUoS is offset by higher wholesale prices.

Table 5 – Locational BSUoS impact depending on existing generators' dispatch behaviour

	Central Scenario		High SG Scenario	
	Generators anticipat loc BSUoS and reduce dispatch	Generators fail to anticipate loc BSUoS or expect others to reduce dispatch	Generators anticipate loc BSUoS and reduce dispatch	Generators anticipate loc BSUoS but expec others to reduce dispatch
Total constraint costs, 2010-20, NPV	£802m	£990m	£1,578m	£1,874m
Increase in constraint costs from I&C, 2010-20 NPV	-£3m	£186m	£551m	£848m

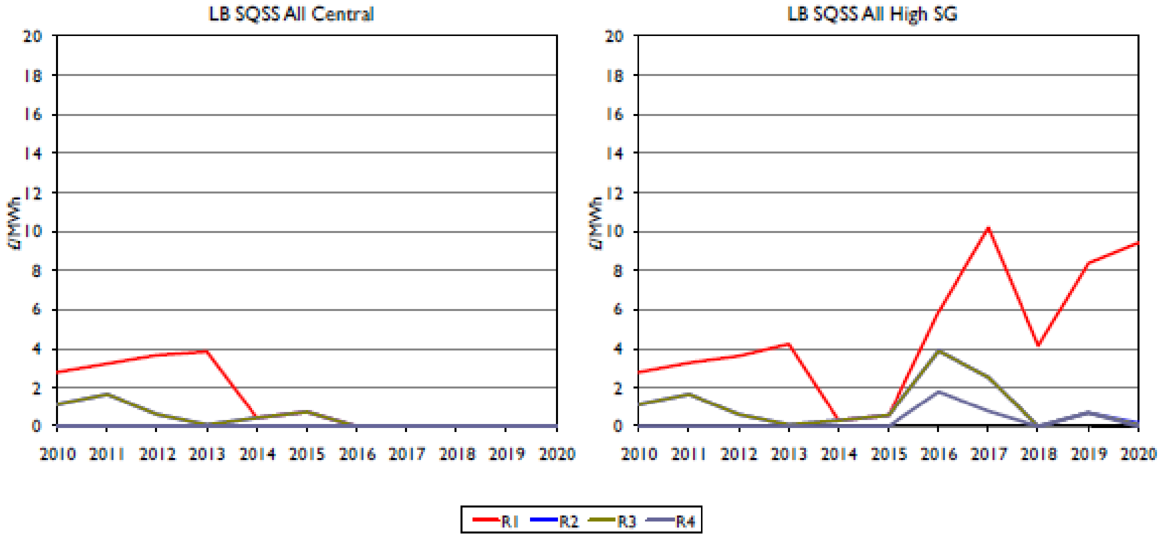
Finally, assessing the different models under these different scenarios highlights one of the key problems with targeting constraints costs. Charges could reach very high levels and be very volatile in parts of the network where generators have no control over their dispatch behaviour. The northernmost zone of Scotland (R1 in the table and chart below), an area with significant wind resource, is the best example. In the high SG scenario with a C&M hybrid model, charges could average around £20 per MWh over the next decade (half of the cost in Table 6, which refers to 100% targeting).

Table 6 – Cost (£/MWh) of targeting 100% of incremental costs to new generators

Zone	2013-16	2014-17	2015-18	2016-19	2017-20
R1	39.03	41.03	37.40	39.34	34.65
R2	27.35	29.08	22.61	21.01	13.15
R3	27.35	29.08	22.59	20.96	12.99
R4	20.67	21.20	15.52	14.88	10.05
R5	2.53	3.28	3.18	3.77	4.14
R6	0.00	0.00	0.00	0.00	0.00
R7	0.00	0.00	0.00	0.00	0.00
R8	0.00	0.00	0.00	0.00	0.00

C&M locational BSUoS could result in a cost of over £10 per MWh in 2017 (Figure 4). In the rest of northern Scotland (R2 and R3), charges could also be very high under the C&M hybrid model. Even the more modest charges resulting from C&M locational BSUoS for R2 could represent a doubling of balancing charges for a Peterhead power station, which could prematurely compromise the plant's commercial viability.

Figure 4 – Additional costs to generators arising from C&M loc BSUoS



H. Implementation

The C&M socialised model is our preferred model because it is the best for encouraging investment, creating the right investment environment in the UK, and ensuring we meet our RES targets. The model is the simplest, the easiest to implement and forms the basis of the model that is currently being used for Interim C&M. The analysis shows the costs of the model are not excessive and are outweighed by the benefits to consumers from tackling climate change and ensuring security of supply. We are also increasing the user commitment which all generators give to the network from the current one financial year to two financial years.

The new grid access regime is being implemented through modifications to industry codes and licences, and these take into account responses to the technical consultation undertaken in March-April 2010. These changes are being made through a Section 84 Commencement Order, using powers derived from Energy Act 2008. The regime will be implemented in July 2010, with specific transitional arrangements for those projects that have already accepted Interim C&M offers.

I. Monitoring and Evaluation

The new regime will be monitored and evaluated by DECC to ensure that the desired benefits are being realised. This would be undertaken as part of the progress report that the UK must submit to the European Commission every two years towards meeting the renewable energy targets (first report due by end-2012).

Ofgem and National Grid will continue monitoring constraint costs on a continuous basis given their importance in determining the Transmission System Operator incentives. Understanding and disentangling the reasons driving constraint costs (whether C&M accelerations, market power or delayed network investment) will become increasingly important.

The Government Response notes that, following the implementation of the reforms, it would be possible for the licence to be amended within the process provided for by section 11A of the Electricity Act 1989. Although the evidence presented here suggests that the costs will be small, the Government Response states that the licence could be amended in the event that costs directly as a result of the Connect and Manage model were considerably higher than expected for an intolerable period, and where all other appropriate options for reducing those costs had been implemented.

J. Specific Impact Tests

Small Firms Impact Test
The 'Connect & Manage' options would create opportunities for small businesses, particularly by helping smaller developers gain easier connection to the grid for their projects. In the short run, small firms in general would be affected by the marginal increase in electricity prices for all electricity users, as part of the overall cost impacts of meeting the 2020 renewable energy target.

Competition Assessment
All four reform options considered in this impact assessment would be expected to reduce the barriers to market entry associated with achieving a connection to the transmission network. This is likely to have a positive impact on competition from a market concentration perspective as it would enable accelerated connection of renewable projects, the ownership of which is relatively diverse. The estimated reduction in wholesale prices resulting from higher levels of renewable generation being connected to the grid could be interpreted as evidence of this.

In its assessment of CAP148,[20] Ofgem noted that any access model that had the potential to increase constraint costs could also increase the risk of anti-competitive behaviour by generators that are in a position to relieve constraints.

Equalities duties (race, disability and gender)
After initial screening as to the potential impact of this policy on race, disability and gender equality, DECC's view is that there will not be a major impact upon minority groups in terms of numbers affected or the seriousness of the likely impact, or both.

[20] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=12&refer=LICENSING/ELECCODES/CUSC/IAS

Annexes

Annex 1 should be used to set out the Post Implementation Review Plan as detailed below. Further annexes may be added to provide further information about non-monetary costs and benefits from Specific Impact Tests, if relevant to an overall understanding of policy options.

Annex 1: Post Implementation Review (PIR) Plan

A PIR should be undertaken, usually three to five years after implementation of the policy, but exceptionally a longer period may be more appropriate. A PIR should examine the extent to which the implemented regulations have achieved their objectives, assess their costs and benefits and identify whether they are having any unintended consequences. Please set out the PIR Plan as detailed below. If there is no plan to do a PIR please provide reasons below.

Basis of the review: [The basis of the review could be statutory (forming part of the legislation), it could be to review existing policy or there could be a political commitment to review];
Review objective: [Is it intended as a proportionate check that regulation is operating as expected to tackle the problem of concern?; or as a wider exploration of the policy approach taken?; or as a link from policy objective to outcome?]
Review approach and rationale: [e.g. describe here the review approach (in-depth evaluation, scope review of monitoring data, scan of stakeholder views, etc.) and the rationale that made choosing such an approach]
Baseline: [The current (baseline) position against which the change introduced by the legislation can be measured]
Success criteria: [Criteria showing achievement of the policy objectives as set out in the final impact assessment; criteria for modifying or replacing the policy if it does not achieve its objectives]
Monitoring information arrangements: [Provide further details of the planned/existing arrangements in place that will allow a systematic collection systematic collection of monitoring information for future policy review]
Reasons for not planning a PIR: [If there is no plan to do a PIR please provide reasons here] We will monitor the model as part of the progress report that the UK must submit to the European Commission every two years towards meeting the renewable energy targets (first report due end-2012). Constraint costs and grid connections are monitored continuously by Ofgem and National Grid. From April 2010 monitoring reports have been available on a monthly basis for constraints. Updates on grid connections are published by National Grid on a quarterly basis

Annex 2: NETWORK CONSTRAINT COSTS – EXPLAINING THE DIFFERENCES BETWEEN NATIONAL GRID'S 2010/11 FORECAST AND REDPOINT'S MODELLING RESULTS

Summary
National Grid are forecasting a cost of £263m (£153m in Scotland) during 2010/11. Redpoint's analysis for the Improving Grid Access impact assessment suggest just over £104m as a result of having to constrain off 1.6TWh (976GWh in Scotland).[21]

Redpoint's analysis and results represent a robust assessment of the differential impact on constraint costs of the various grid access models considered by the Government, notwithstanding the large differential between their results and National Grid's short term forecasts.

Redpoint's modelling and National Grid's forecast have different purposes. The objective of Redpoint's modelling is to provide reliable estimates of the impact of different grid access regimes on constraints over the *longer* term. The objective of National Grid's forecast is to establish a *short-term* benchmark encompassing all costs to provide greater certainty and transparency to the market.

It is therefore not surprising that results differ. In particular the assumptions and bearing of factors such as market power and also local network constraints are not the same. In our view there are other tools to mitigate constraints arising as a result of these factors, and therefore their bearing on the impact of the grid access models assessed should be limited.

Detail
The following paragraphs present our understanding of the key drivers of these differences.

1. Demand fall and the merit order
National Grid's data show that output from GB generators connected to the transmission grid fell by 5% in 2009 with respect to the previous year and by 5.6% with respect to two years earlier. Combined with increases in generation capacity connected to the grid, this has resulted in load factors for GB plant falling from 52% in 2007 to 51% in 2008 to 48% in 2009.

In these market conditions, Redpoint's modelling suggests that under DECC's central fuel price assumptions, load factors for conventional Scottish thermal generation would be substantially lower than has been observed historically. The difference in these load factors fully explains the difference between Redpoint's estimates and NG's forecast in the volume of Scottish constraints, which in turn account for about two thirds of total constraints.

In its final SO Incentives proposals for 2010/11 Ofgem highlights that National Grid's problems forecasting constraint costs are partly the result of NGET relying too heavily on historical data and not considering the impact of market fundamentals and how these might develop. This is likely to explain a large part of the difference between NGET's forecasts and Redpoint's constraints estimates.

Another possible explanation for the difference in load factors is market power. Ofgem's concern about potential market power was the main rationale for seeking to include a Market Power Licence Condition (MPLC) power in the Energy Act 2010. The impact assessment for the Bill included Ofgem's assessment that market power may have been responsible for between £125m and £151m of a total £238m of constraint costs in 2008/09.

[21] These figures refer to total constraint costs and not the incremental costs resulting from the different access models that are the focus of Redpoint's analysis.

Redpoint's modelling assumes no market power or other non-economic dispatch is exercised by generators behind a network constraint and therefore implies that regulation of any market power is successful. National Grid's forecasts have to build on the observed constraints. Thus, National Grid's 2010/11 forecast should be higher than Redpoint's constraint estimate.

In any event, the constraints identified by National Grid are not directly related to the implementation of any particular grid access model such that it affects the reliability of Redpoint's estimate of the differential impact of the various access model over the longer term.

2. Local constraints
Redpoint's analysis is based on modelling electricity flows over seven network boundaries. Historically with an 'invest then connect' regime constraints on these boundaries have accounted for close to 90% of all constraint costs.

However, National Grid's forecast suggests that in 2010/11 local network outages related to Grendon and Staythorpe works in the Thames Estuary area will account for £87 million in constraint costs and 779GWh of constrained volume. These costs were not known at the time of Redpoint's modelling and were therefore not included. More importantly, in so far as these constraints are the result of more localised issues than those which are captured by the seven boundaries considered in Redpoint's analysis, they could not have been captured even if known.

3. Other issues
The two reasons above explain virtually all of the differences between Redpoint's estimates and National Grid's forecasts for 2010/11. However, there are some other issues that might also have a small bearing on these differences.

3.1 Redpoint's interconnector assumptions are oversimplified. Redpoint have assumed that the Anglo-French interconnector imports power from France half of the time, totalling imports of 8.76TWh per annum. Recently the interconnector has been used to export power and this has meant that net imports for 2009 were only 3.3TWh.

A related issue is the fact that the assumption that the interconnector imports half the time underestimates the flows. For example, even though net imports in 2009 were 3.3TWh, total flows were exports of 3.3TWh and imports of 6.6TWh.

3.2 LCPD running hours are limited and this might affect the way Cockenzie behaves.
Whereas it is true that the Large Combustion Plant Directive (LCPD) complicates dispatch decisions, it is unlikely to mean that any power station would be made to run at a loss.

Redpoint's modelling suggests that using DECC's central fuel price assumptions and given the expected changes in electricity demand over the next few years, Cockenzie would not use up all of its 20,000 LCPD running hours by 2015. The running hours limitation is a ceiling – there is no reason why companies have to exhaust them.