

Title: Impact Assessment of the Transmission Constraint Licence Condition (TCLC) IA No: DECC0045 Lead department or agency: DECC Other departments or agencies: Ofgem	Impact Assessment (IA)				
	Date: 8/12/2011				
	Stage: Consultation				
	Source of intervention: Domestic				
	Type of measure: Other				
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Summary: Intervention and Options	RPC: AMBER
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Cost of Preferred (or more likely) Option				
Total Net Present Value	Business Net Present Value	Net cost to business per year (EANCB in 2009 prices)	In scope of One-In, One-Out?	Measure qualifies as
£4.2m	£3.7m	£-0.8m	Yes	Zero Net Cost

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

Companies with generation located in a transmission-constrained region may be able to engage in exploitative behaviour. Situations can arise where a generator has the opportunity to act in such a way as to make it very likely that National Grid will be compelled to accept its offers, bids or inter-trip contracts at an unduly high price in order to balance the network. Ofgem has estimated that the costs to consumers of this exploitative behaviour were approximately £125m in 2008/09. In the longer term, upgrades to the transmission system and changes to market arrangements may reduce the potential for such exploitation. However, action over the medium term is needed to reduce unnecessary and significant financial costs to consumers.

What are the policy objectives and the intended effects?

The policy objective is to restrict opportunities for generation companies to exploit periods of transmission system constraint, resulting in higher than necessary bills for consumers, by introducing a time-limited condition in generators' licences (TCLC). It is the Government's intention that enforcement orders in relation to breaches of the TCLC should be subject to appeal to the Competition Appeal Tribunal (CAT). We have sought to ensure that the TCLC can be enforced at low cost and that it does not introduce uncertainty into the GB electricity market that could undermine investment and hence security of supply.

What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)

Option 1 would prohibit, during a transmission constraint period: dispatching or withholding one or more generation units in circumstances when the generator had more economic options available; and exploitative prices to reduce/cease generation when an export constraint is active. Option 2 is as Option 1, but would also prohibit exploitative prices to increase generation when an import constraint is active. Option 3 is as Option 2, but would also contain a general condition, prohibiting any other circumstances where generators obtain "excessive benefits" in relation to a change in generation during a constraint. Option 1 is our preferred option, and should deliver benefits to consumers, with limited impacts on investment and existing peaking plant. Option 2 would have similar net monetised benefits, but would tend to undermine incentives to build or schedule plant where it is most needed to reduce constraints. Monetised net benefits from Option 3 are uncertain, and it could create additional uncertainty for investment.

Will the policy be reviewed? It will be reviewed. If applicable, set review date: 2016/17					
Does implementation go beyond minimum EU requirements?			N/A		
Are any of these organisations in scope? If Micros not exempted set out reason in Evidence Base.	Micro Yes	< 20 Yes	Small Yes	Medium Yes	Large Yes
What is the CO2 equivalent change in greenhouse gas emissions? (Million tonnes CO2 equivalent)			Traded: 0.09		Non-traded: N/A

I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister: _____ Date: _____

Summary: Analysis & Evidence

Policy Option 1 (preferred)

Description: Option 1 would prohibit, during a transmission constraint period: dispatching or withholding one or more generation units in circumstances when the generator had more economic options available (“non-economic dispatch”); and exploitative bids/inter-trip prices when an export constraint is active.

Note: Costs and benefits of Options 2 and 3 are discussed in more detail in the Evidence Base section.

FULL ECONOMIC ASSESSMENT

Price Base Year 2009	PV Base Year 2011	Time Period 7 Years	Net Benefit (Present Value (PV)) (£m)		
			Low: -4.5	High: 31.6	Best Estimate: 4.2

COSTS (£m)	Total Transition (Constant Price) Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	N/A	0.0	0.0
High		1.0	4.5
Best Estimate		0.5	2.1

Description and scale of key monetised costs by ‘main affected groups’

Investigation costs, borne by Ofgem and generators.
Appeal costs, borne by Ofgem, generators and the CAT.

Other key non-monetised costs by ‘main affected groups’

Set-up and monitoring costs: negligible.
Impact on peaking plant operation (security of supply): potential for accelerated closure of thermal plant in constrained regions – likely minimal.
Impact on investment: reduction in returns to investment to some plant, due to lower payments received from National Grid – likely small, in comparison to overall drivers of investment.

BENEFITS (£m)	Total Transition (Constant Price) Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low	N/A	0.0	0.0
High		7.3	31.6
Best Estimate		1.5	6.3

Description and scale of key monetised benefits by ‘main affected groups’

Because of reduced constraint costs, there will be a reduction in retail electricity prices, due to lower network balancing charges, leading to a slight increase in electricity consumption, to the extent that consumption is responsive to prices. This should lead to an overall welfare gain: the value that consumers are willing to pay for the increased consumption, as embodied by the retail electricity price, is greater than the increased resource costs (including traded sector emissions) from (slightly) increased consumption of electricity.

Other key non-monetised benefits by ‘main affected groups’

Impact on investment – reduced balancing charge levels and volatility could reduce barriers to new investment – likely small.
Impact on future constraint costs – reduced incentives to invest in plant in export-constrained regions could reduce future constraint costs – likely small.
Benefits to consumers (distributional impact), estimated at between around £115m and £300m (PV).

Key assumptions/sensitivities/risks

Discount rate (%) 3.5%

Monetised estimates of costs, benefits and distributional impacts above are dependent on a number of assumptions (for example, on number of appeals, number of investigations, effectiveness/credibility of the licence condition and “baseline” constraint costs). These assumptions are discussed in more detail in the “Evidence Base” section.

BUSINESS ASSESSMENT (Option 1)

Direct impact on business (Equivalent Annual) £m:			In scope of OIOO?	Measure qualifies as
Costs: 0.1	Benefits: 0.9	Net: 0.8 (benefit)	Yes	Zero Net Cost

Evidence Base (for summary sheets)

Contents

Background	4
GB wholesale electricity trading arrangements	4
Transmission network constraints.....	4
The balancing market: National Grid and the management of constraints	4
Problem under consideration.....	6
Summary	6
The factors behind the ability to engage in exploitative behaviour at times of constraint.....	6
Potential types of exploitative behaviours	6
The scale of the problem	7
Rationale for intervention.....	7
Summary	7
The need for direct intervention	8
The limitations of Ofgem’s existing competition powers	9
The rationale for a Secretary of State licence modification	9
Limitations with other options.....	9
Policy objective.....	10
Options under consideration.....	10
Cost-benefit analysis	11
Summary and comparison of options.....	11
Option 1.....	12
Option 2.....	17
Option 3.....	18
Distributional impacts	19
Reduction in constraint costs	19
Net direct costs to business	19
Risks and assumptions.....	20
Specific impact tests.....	20
Competition impacts	20
Microbusiness impacts	21
Equalities.....	21
Human Rights.....	21
Greenhouse gas impacts.....	21
Post-implementation Review	21
Annex A – estimating reductions in constraint costs from the TCLC (Option 1)	22

Background

1. The Energy Act (2010) introduced a power for the Secretary of State to modify electricity generators' licences to address specific areas of potential exploitative behaviour in the wholesale electricity market. This Impact Assessment (IA) accompanies the consultation on the draft Transmission Constraint Licence Condition (TCLC), and considers the different options for introducing a TCLC.
2. In order to better understand the proposals, it is important to understand a number of wholesale electricity market characteristics. These include:
 - Great Britain (GB) wholesale electricity trading arrangements;
 - Transmission network constraints; and
 - National Grid's role in resolving constraints.
3. We discuss these in more detail below.

GB wholesale electricity trading arrangements

4. Electricity is produced by generators. Electricity flows to final consumers through the (high voltage) GB transmission network, and then through (low voltage) local distribution networks.
5. Energy suppliers are the commercial interface between generators and the majority of consumers. Electricity is sold by generators in the wholesale market to suppliers, who then pass on their costs through bills to their domestic and business customers¹.
6. Importantly, the contract between the supplier and the generator only relates to the amount of electricity required. It does not specify where in GB that electricity has to be produced.

Transmission network constraints

7. The GB transmission system has a finite capacity to transmit electricity between any two locations, and has not been designed in order to meet every possible supply and demand scenario. If flows on the system are too high, parts of the network can overload leading to system insecurity. Where the capacity of the network between two locations is insufficient to transmit electricity from where it is produced to where the demand for it is situated, that is termed a "transmission constraint" (referred to in this paper as "constraints"). Constraints can arise due to thermal limitations on the system; the need to ensure pre- and post-fault voltage levels remain within prescribed limits, or to ensure the electrical 'stability' of the transmission system.
8. A common example of the problem is when too much generation has been scheduled for production in Scotland and there is not enough capacity on the network to transmit this excess electricity to England and Wales (the corresponding bottleneck is known as the "Cheviot Boundary"). Such a constraint, where a smaller region cannot transmit to larger region, is known as an "export constraint". The reverse, where the smaller region requires energy *from* the larger region, is known as an "import constraint".
9. Constraints can occur anywhere on the transmission system. While currently the major constraint is the Cheviot Boundary, as the electricity system develops over the coming years, we expect constraint issues could arise elsewhere in England and Wales. Constraints also commonly occur within Scotland.

The balancing market: National Grid and the management of constraints

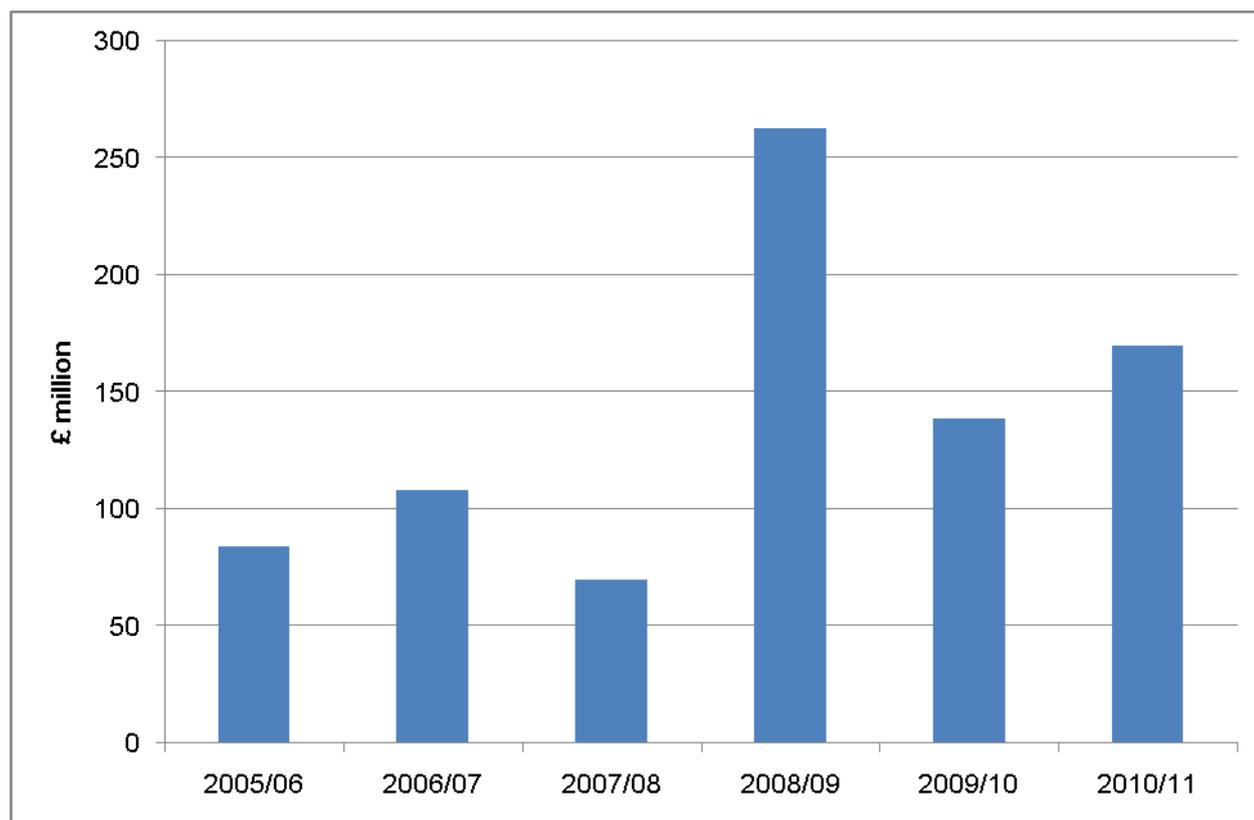
10. As part of its remit, National Grid has the responsibility for overseeing and managing the flow of electricity across the whole of the GB transmission network, including the elements owned and operated by the Scottish transmission network owners. Consequently, it is National Grid's responsibility to ensure that the network is balanced either side of any constraint (in order to maintain the stability of the system).
11. The wholesale market is divided into 30 minute periods for trading purposes; "normal" trading occurs until one hour prior to the start of each period – a point known as "gate closure". After gate closure, electricity generators and purchasers may not trade any further with each other, but may trade with National Grid.
12. Generators' initial decisions regarding which plant to "dispatch" electricity from are not dependent on the ability of the network to transmit to the location of demand. A generator's dispatch decisions are generally based on meeting its contracted position by generating its most profitable plant. From the

¹ It is also possible for large business users to buy electricity on the wholesale market directly from generators.

resulting decisions, generators provide National Grid with a Final Physical Notification (FPN) of electricity output for each power station at gate closure.

13. Although they will have previously monitored proposed output, it is by considering the submitted FPNs that National Grid will know for definite whether there are any constraints on the system and, if so, where it will need to trade with companies to increase or decrease generation in particular locations (e.g. if there is too much generation in Scotland and not enough transmission capacity to take the electricity to England, National Grid will have to reach an agreement² with a company in Scotland to reduce its generation and pay another company in England to increase its generation). National Grid can trade through a separate market arrangement termed the Balancing Mechanism (BM). This operates by generators submitting monetary “offers” to increase or “bids” to decrease the amount of electricity they produce from a particular plant. Other commercial tools are also available to National Grid and can include previously arranged bilateral deals, such as inter-trip contracts³.
14. Importantly, the costs that National Grid incurs from managing constraints on the network are subsequently charged to generators and suppliers in proportion to their share of the market across Great Britain (via Balancing Services Use of System, or “BSUoS”, charges), effectively resulting in a “socialised” charge which is ultimately paid by all consumers. These charges are known as “constraint costs”, and were £170m in 2010/11. Figure 1 below shows outturn historical constraint costs in GB, since 2005/06, when the Scottish and England & Wales markets were joined. Constraint costs have fallen since the recession (with reduced electricity demand), but are higher now than in 2005/06. Historically, Scottish constraints (particularly along the Cheviot boundary between Scotland and England) have accounted for the majority of these costs.

Figure 1 Historical GB constraint costs



Source: National Grid

² Importantly, this agreement usually involves a “bid” put forward by a company that equates to an amount that *they* will pay National Grid not to generate. The company will have already received payment from its original contract to produce electricity (e.g. with a supplier). Thus, one would expect generators to be willing to bid up to the value of their fuel costs and other variable costs avoided by reducing generation.

³ Inter-trips are arrangements where National Grid can agree with a company to “arm” a generation plant so that the system, if it were to have too much generation on the network, can automatically trip off that plant. The negotiated “arming fee” is based on the overheads of having the inter-trip in place and the risk that it might be used.

15. Moreover, these costs are expected to increase over the medium term. Modelling undertaken by Redpoint Energy (“Redpoint”) suggests that, in some scenarios, constraint costs could be over £400m annually in some years to 2020.

Problem under consideration

Summary

16. Companies with generation located in a transmission-constrained region may be able to offer balancing services at prices higher than under competitive market conditions. Situations can arise where a generator has the opportunity to act in such a way as to make it very likely that National Grid will be compelled to accept its offers, bids or inter-trip contracts at an overly high price in order to ensure the balancing of the network. Ofgem have estimated that the costs of such actions to consumers were approximately £125m in 2008/09⁴.

The factors behind the ability to engage in exploitative behaviour at times of constraint

17. The nature of the GB market means that companies that have generation plant “behind” a constraint (i.e. they are in the smaller geographic region), particularly where there are a limited number of generators in that region, may be able to offer “system balancing services” to National Grid (i.e. services to help National Grid resolve transmission constraints) at prices higher than under competitive market conditions.
18. In general, high prices for providing balancing services in a particular region might be expected to attract new entry to the regional market. However, there are significant barriers to entry into balancing services markets. Essentially, entry would involve one of the following:
- the construction of a flexible power station in the import- or export-constrained⁵ region;
 - the provision of highly flexible demand-side response; or
 - the construction of “interconnection” (transmission) capacity to other countries.
19. Other factors may also contribute to the ability to engage in exploitative behaviour, including:
- limited demand-side responsiveness (low “elasticity” of demand) in the very short-term;
 - limited storability of electricity; and
 - the need for National Grid to ensure (almost continuously) that electricity supply and demand balance and that flows do not exceed the capability of the transmission network.

Potential types of exploitative behaviours

20. In summary, situations can arise where a generator has the opportunity to act in such a way as to make it very likely that National Grid will be compelled to accept its offers, bids or inter-trip⁶ contracts at an overly high price in order to ensure the balancing of the network. Such potential actions include:
- **Non-Economic Dispatch:** The generator notifying National Grid, through the FPN, that it intends to dispatch its plant in ways that would not normally be economic given the spreads⁷ available in the GB-wide wholesale market because it knows, or is able to predict, that National Grid will need to call on that plant in order to balance the system. For example, this could take the form of a generator (a) submitting an intention to produce electricity from a plant in an export constrained region, despite negative GB market spreads, (b) submitting an intention not to produce electricity from a plant in an import constrained region, despite positive market spreads, or (c) generally not dispatching its most economic plant, in each case creating or exacerbating a transmission constraint.
 - **Pricing Behaviour in Export Constraints:** Not manipulating generation availability, but taking advantage of both being behind an export constraint and being required to be called on by National Grid to arrange for generation to be reduced in a particular location. In such situations National Grid

⁴ Ofgem (2009) “Addressing Market Power Concerns in the Electricity Wholesale Sector - Initial Policy Proposals”

⁵ The construction of plant in an export-constrained region is problematic, as it would tend to exacerbate the problem of export constraint volumes.

⁶ See footnote 3.

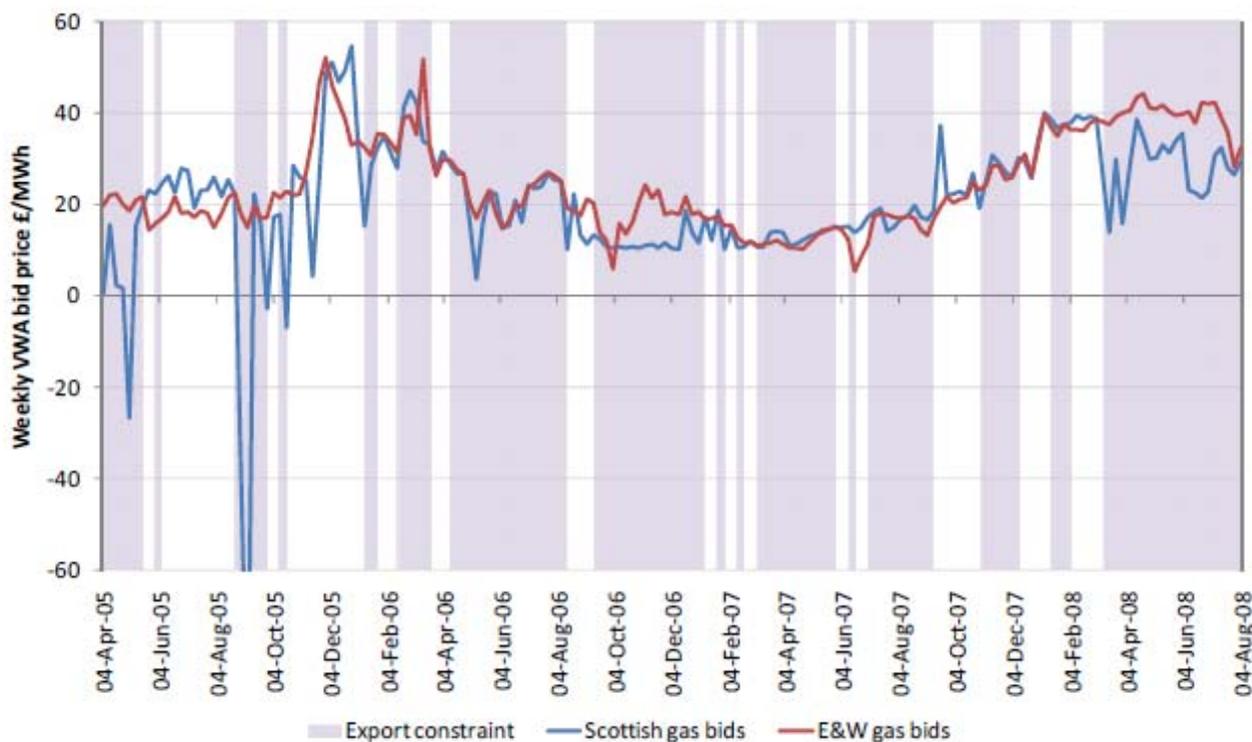
⁷ Spreads represent the difference between the short-run marginal costs of generation (which typically include fuel costs, some short-run variable costs and the costs of CO₂ allowances) and the wholesale price of electricity. Common parlance in the industry refers to “clean spark” spreads as the difference between wholesale electricity prices and fuel/carbon costs for CCGT generators, and “clean dark” spreads as the difference between wholesale electricity prices and fuel/carbon costs for coal generators.

would have no option but to accept the “bid” submitted. A company might also use their market power in the region to extract unduly high arm's length fees for inter-trip contracts from National Grid.

The scale of the problem

21. Figure 2 below illustrates that export constraints between England/Wales and Scotland were present to some degree in most weeks over April 2005 to August 2008. Large BM bid price differentials may be observed in a number of export constraint periods, including September 2005 and Summer 2008.

Figure 2 Accepted BM Bids in constrained and non-constrained periods, Scottish gas plant versus E&W gas plant April 2005-August 2008



Source: Ofgem (2009) “Addressing Market Power Concerns in the Electricity Wholesale Sector - Initial Policy Proposals”

22. In their March 2009 consultation document on addressing market power concerns in the electricity wholesale sector⁸, Ofgem estimated that of the £238m of (forecast) total out-turn constraint costs in 2008/09, £125m was due to pricing behaviour in constraints. More recent estimates by Ofgem indicate that between £19m-36m of the total out-turn constraint costs in 2008/09 could be due to non-economic dispatch, with £106m-£115m attributable to pricing behaviour in export constraints.

Rationale for intervention

Summary

23. This section considers the rationale for the Secretary of State to introduce a time-limited⁹ condition in generators’ licences to allow Ofgem to take action against the specific forms of exploitation during transmission constraints discussed above (see paragraph 20). In the longer term, upgrades to the transmission system and changes to market arrangements may reduce the ability for such exploitation. However, action over the medium term is needed to reduce unnecessary and significant financial costs to consumers.
24. Due to difficulties in applying existing competition law in this context, it is difficult for Ofgem to take action against this behaviour with its existing powers. By implementing the licence condition directly (instead of Ofgem), Government is able to introduce a tailored appeals process, which benefits business, by reducing uncertainty over whether they could be unfairly penalised. In addition, there are limitations

⁸ Ofgem (2009) “Addressing Market Power Concerns in the Electricity Wholesale Sector - Initial Policy Proposals”

⁹ The Energy Act 2010 sets out a sunset clause that means the licence condition can only be in place for a maximum of 7 years – an initial 5 year period that may be extended by 2 years through secondary legislation.

associated with alternative options (including non-regulatory alternatives) to tackle such specific forms of exploitative behaviour, which we discuss in more detail below. Table 1 contains a summary.

Table 1 Comparison of alternative options, relative to a Secretary of State TCLC

	Effectiveness in reducing market power-related constraint costs	Other considerations
Competition Act 1998 powers	Limited – due to difficulties in defining relevant market and establishing individual dominance	
Ofgem TCLC	Similar	Additional uncertainty to business, due to lack of tailored appeals process
CC reference	Uncertain – depends on action taken by CC	Not proportional to problem identified; additional uncertainty to business, while CC reference goes on
Ex-ante price regulation	Similar	Insufficiently flexible; more distortive to competition; greater potential to be seen as interventionist
National Grid constraint management contracts with conditions on BM bids/offers	Limited – contracts rarely used by National Grid (and companies not obliged to take them)	Could be gamed
EU Regulation on Energy Market Integrity and Transparency	Uncertain – depends how implemented and enforced by regulators	Will take time to come into force; additional uncertainty to business, in the absence of specific licence conditions clarifying acceptable behaviour

The need for direct intervention

25. Although it does not provide direct solution to the underlying causes of market power-related constraints, the TCLC would prevent manipulation of the market during a time where the process of upgrading the transmission system will create more potential for such exploitation to occur (during, for example, maintenance outages). Completed upgrades of GB transmission infrastructure¹⁰ will go a long way to providing a solution to the overall problem of constraints. Nevertheless, at this point in time, and at least for the next five years, there is a need to act.
26. In the long-term, changes to market rules may act to reduce constraints and scope for exploitation going forward. For example, a move to “splitting” the GB wholesale market into geographically separate regions, with potentially different wholesale prices in each zone, and trade between zones. “Market splitting” would reduce the potential for manipulation of transmission constraints in the balancing mechanism, since constraints would be explicitly accounted for in the zonal wholesale market prices¹¹, rather than being left for National Grid to deal with using the BM.

¹⁰ Ofgem are currently minded to approve funding for National Grid Electricity Transmission (NGET) and Scottish Power Transmission Ltd (SPTL) to construct the Western High-Voltage Direct Current (HVDC) link between Scotland and England for delivery in 2015 (http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/CriticalInvestments/InvestmentIncentives/Documents/1/TII_Aug11_WHVDC_FINAL.pdf). Details of possible future reinforcements (subject to detailed proposals by the Transmission Owners, Ofgem’s approval and planning consent) are described by the Electricity Networks Strategy Group (see http://webarchive.nationalarchives.gov.uk/20100919181607/http://www.ensg.gov.uk/assets/1696-01-ensg_vision2020.pdf). For the latest information on Ofgem electricity transmission investment approvals visit <http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/CriticalInvestments/InvestmentIncentives/Pages/InvestmentIncentives.aspx>.

¹¹ For example, under market splitting, any expectation of an export constraint would tend to drive the wholesale price down in the export-constrained zone, reducing the incentive to dispatch electricity, and thereby reducing/eliminating the export constraint. However, the incentive to create an import constraint could, however, remain, as this would drive the wholesale price up in the import-constrained zone.

27. At a European level, the debate for greater integration of electricity markets is already focused on market splitting approaches. In due course, options for more fundamental change to GB trading arrangements may come to the fore as a result of European developments. Ofgem is, in parallel with its work on electricity transmission charging under Project TransmiT, continuing to consider the consequences of European developments for the arrangements in GB and whether or not these developments imply the need for reform of the GB market¹².
28. However, fundamental reform of GB market arrangements will take time to deliver. It is important that consumers are protected now, especially given the barriers to entry that exist in the balancing services market (see “Problem under consideration” section above).

The limitations of Ofgem’s existing competition powers

29. Ofgem’s March 2009 consultation followed a particular case of possible market abuse by Scottish Power and Scottish & Southern Energy, which Ofgem investigated through their existing competition law powers. This case was closed in January 2009, with Ofgem noting that “...the likelihood of making an infringement decision under the Competition Act 1998 is low”. The limitation with competition law relates to difficulties in defining the electricity market, both temporarily and geographically, in which a company might exploit its position. It may also be difficult to identify legally whether a company could be said to be individually dominant at any point in time, given that market power is often held by two or more companies simultaneously. Some respondents to Ofgem’s 2009 consultation queried whether Ofgem’s Competition Act 1998 (CA98) powers, along with other powers, had been used to their full extent. However, we believe that a specific and targeted licence condition is more likely to achieve the intended objectives (of savings to consumers), at lower resource cost (in terms of investigations). Note that the TCLC is not intended to displace the application of competition law where appropriate.

The rationale for a Secretary of State licence modification

30. Potentially, Ofgem could introduce a TCLC itself, with potentially similar reductions in constraint costs. However, a Secretary of State licence modification is the preferred option as it will also allow the introduction of a tailored appeals process against enforcement orders in relation to the TCLC. The Utilities Act 2000 introduced a right to appeal a finding of an ordinary licence breach to the High Court in England and Wales or the Court of Sessions in Scotland. The TCLC proposal includes the right for a company to appeal direct to the Competition Appeal Tribunal (CAT), which is better placed to consider complex questions of competition law, compared to the courts. This benefits business, by reducing uncertainty over whether they could be unfairly penalised. Many generators, in their responses to Ofgem’s March 2009 consultation, expressed support for a dedicated appeals mechanism.

Limitations with other options

31. In its March 2009 consultation document, Ofgem considered different policy options for tackling the issue of undue exploitation of market power in the GB wholesale electricity sector. There appeared to be only three credible approaches at the time that could deal with the concerns: a licence condition, price capping or some form of divestment. While some form of divestment, e.g. of a generation plant, might improve competition, it would only be possible through a Market Investigation Reference (MIR) to the Competition Commission (CC). Ofgem considered that, while there might be merits to a MIR, it would also be time- and resource-intensive, would not be proportional to the problem identified, and could introduce additional uncertainty for investment, with possible security of supply or cost implications. In general, an MIR could take 18-24 months, plus time for appeals to be heard and remedies to be implemented. The CC would also be free to amend any scope for the MIR suggested by Ofgem, which means the MIR would not necessarily be limited to the problem identified. The CC could propose any solutions it felt necessary, i.e. it would not be limited to mandating the structural changes considered by Ofgem – it could also require behavioural changes, or make recommendations to Government on changes to legislation.
32. The other credible option discussed in the consultation paper would be some form of ex-ante regulation (i.e. price capping), which is commonly applied in the US electricity markets, and could deliver similar reductions in constraint costs to a TCLC, depending on the details of implementation. However, there are significant downsides to this approach, including: not being sufficiently flexible to deal with all issues that could arise in the market; distorting competition by placing greater restrictions on pricing behaviour; and being “interventionist” by the standards of the GB market, hence sending negative signals to investors.

¹² http://www.ofgem.gov.uk/NETWORKS/TRANS/PT/Documents1/110527_TransmiT_charging_letter.pdf

33. In its final decision letter on National Grid's electricity System Operator (SO) Incentives for 2011 to 2013¹³, Ofgem considered whether it would be appropriate to allow National Grid to enter into contracts with parties for constraint management services that apply conditions to the submission of bid/offer prices. Such contracts could reduce constraint costs, though parties would not be obliged to enter into them. Ofgem determined it was appropriate to temporarily restrict National Grid's ability to enter into such contracts, as it considered that this ability meant that it could influence pricing in the BM. This could result in National Grid gaming the incentive for its benefit, with presumably uncertain benefits for constraint cost reductions. While Ofgem is not generally disposed to imposing a temporary restriction on such behaviour, it considered that the scope for gaming, and National Grid's indication that it rarely uses such contracts, meant that this could occur with very limited impact on National Grid's day to day commercial activity. Importantly, National Grid accepted Ofgem's concerns and indicated that action to limit this activity, until this issue can be resolved, is appropriate.
34. The European Commission has also recently recognised that the nature of the electricity market may mean that it could be susceptible to some form of market manipulation. The Regulation on Energy Market Integrity and Transparency (REMIT) proposals, adopted by the European Council on 10 October 2011, contain text that prohibits, among other things, withholding of output. However, it is likely that these proposals will take some time to come into force. The Government and Ofgem believe, however, that a specific and targeted licence condition gives greater clarity to generators as to what is acceptable behaviour, compared to the more general definitions currently contained in the REMIT text. We will ensure that the TCLC will be implemented in a manner consistent with REMIT.

Policy objective

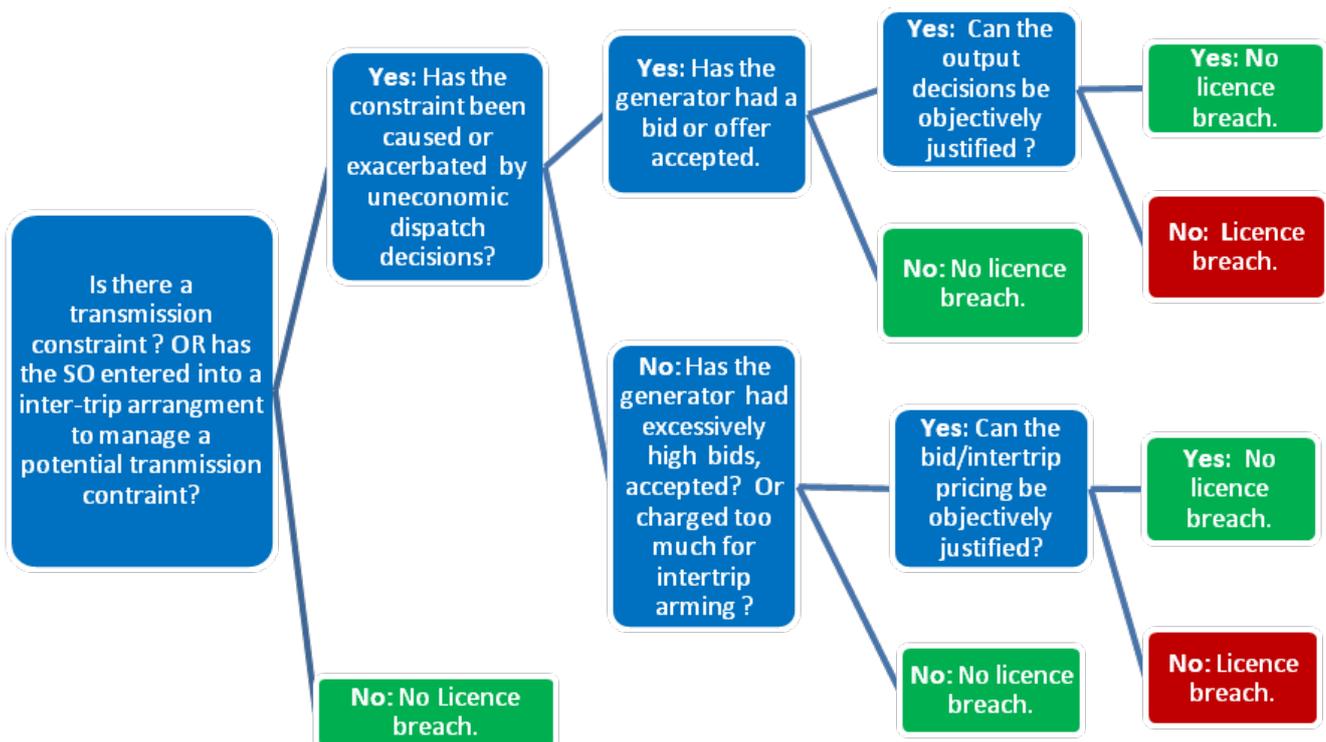
35. The policy objective is to restrict opportunities for generation companies to exploit periods of transmission system constraint, resulting in higher than necessary bills for consumers (see "Problem under consideration" section above), by introducing a time-limited TCLC.
36. It is the Government's intention that enforcement orders in relation to breaches of the TCLC should be subject to appeal to the Competition Appeal Tribunal. In designing the TCLC, we have sought to ensure that it can be enforced at low cost and that it does not introduce uncertainty into the GB electricity wholesale market that could undermine investment and hence security of supply.

Options under consideration

37. We consider the following options for a TCLC, all of which would be consistent with the provisions of the Energy Act 2010.
38. Option 1 would prohibit, during a transmission constraint period:
- dispatching or withholding one or more generation units in circumstances when the generator had more economic options available ("non-economic dispatch"); and
 - exploitative bids/inter-trip prices when an export constraint is active.
39. Figure 3 below provides a high-level illustrative example of how Ofgem will determine whether a breach of the TCLC has occurred (under Option 1). In summary, there would be some initial tests for exploitative behaviour, but Ofgem would seek to find out whether any actions taken could be "objectively justified", before deciding whether there was a breach of the licence condition.

13

Figure 3 TCLC process



Source: Ofgem

40. Ofgem has powers under the Gas and Electricity Acts to require that it be provided with information when it appears that there may be a breach of a licence obligation. Ultimately, if a company were found to be in breach of its licence obligations, Ofgem has the power to impose a financial penalty of up to up to 10 per cent of its total turnover. As such, we expect the introduction of the TCLC to act as a deterrent.
41. Option 2 is as Option 1 above, but would also prohibit exploitative offers when an import constraint is active.
42. Option 3 is as Option 2 above, but would also contain a general condition, prohibiting any other circumstances where generators are able to obtain “excessive benefits” in relation to an increase or decrease in generation during a transmission constraint period.
43. The Energy Act 2010 requires Ofgem to publish a document setting out advice and information on the Authority’s intended approach to the interpretation and enforcement of the TCLC. In its consultation on the draft Guidance for the TCLC, Ofgem is consulting on the details of implementation and enforcement.

Cost-benefit analysis

Summary and comparison of options

44. This section examines the costs and benefits of the TCLC, and the various options for its implementation. We first consider the costs and benefits of Option 1, relative to a counterfactual scenario of no action to tackle exploitative behaviour. As discussed above (see “Rationale for Intervention” section), other developments may take place within the next 5 years, which may allow Ofgem to take action on exploitative behaviour behind transmission constraints. We then compare the incremental costs and benefits of Options 2 and 3, relative to Option 1.
45. The TCLC will also result in transfers of income from some generators to National Grid via reduced constraint payments. National Grid’s cost savings will result in benefits to consumers. Distributional impacts are considered in a separate section.

46. We assume the policy starts in 2013 (implementation is due for April/October 2012), and lasts for 5 years. Though the policy could be allowed to continue in force for a maximum of another 2 years beyond this, and could thus deliver benefits beyond 2017, this will be subject to a future review and secondary legislation. In line with “one in, one out” (OIOO) guidance, we discount costs and benefits back to 2010. All costs and benefits are quoted as 2009 prices.
47. In summary, Option 1 should deliver benefits to consumers (and society), with limited impacts on investment and existing peaking plant, and is currently our preferred option. Option 2 has the potential to deliver small additional (static) benefits to consumers (and society) above Option 1, but reduces incentives to locate generation where it is most needed and could would tend to result in increased future constraint costs. Option 3 could deliver additional benefits to consumers (and society), although this is uncertain in the absence of evidence of specific behaviours to be targeted by the general condition. In addition, Option 3 could entail additional administrative costs, while creating additional uncertainty for business. We are consulting on whether there are specific types of exploitative behaviour not captured by the prohibitions under Option 1 or 2. Therefore, at this point, it is difficult to be specific on the costs and benefits of Option 3. Table 2 provides a high-level comparison of the policy options. More detail is provided in the following sub-sections.

Table 2 High-level comparison of policy options

	Option 1	Option 2	Option 3
Monetised NPV (central, £m)	4.2	4.2 (approx)	Uncertain – could be greater or smaller than Option 1
Impacts on investment	+ve/-ve (small)	+ve/-ve (small)	-ve (potentially large)
Impact on existing peaking plant	-ve (small)	-ve (small, though larger than Option 1)	-ve (at least as large as Option 2)
Reduction in future constraint costs	+ve (small)	+ve/-ve (small)	+ve/-ve

Source: Table 3 for monetised NPV.

Option 1

48. The monetised costs and benefits of Option 1 are summarised in Table 3 below. Costs arise from assumed numbers of investigations and appeals. Benefits arise due to increased consumer welfare from increased electricity consumption, above the costs of supplying the electricity. More detail on these estimates is provided below.

Table 3 Present value of net monetised benefits to society from Option 1 (£m)

	Costs	Benefits	Net benefits
Low	4.5	0.0	-4.5
Central	2.1	6.3	4.2
High	0.0	31.6	31.6

Source: Table 4, Table 5, Table 6, Table 7. Note: “Low” net benefit scenario based on “high” cost and “low” benefit estimates from source tables. “High” net benefit scenario based on “low” cost and “high” benefit estimates from source tables.

49. In addition, there are the following non-monetised impacts.
- set-up and monitoring costs, borne by Ofgem;
 - impacts on investment;
 - risk of accelerated closure of existing flexible plant; and
 - dynamic impacts on future constraint costs.

Monetised costs

50. The monetised costs to society, as a result of Option 1, are:
- investigation costs, borne by Ofgem and generators; and
 - appeal costs, borne by Ofgem, generators and the CAT.

Investigation costs

51. Ofgem estimated that the Competition Act 1998 (CA98) investigation into SP and SSE in 2008 cost around £540k in resource costs. This is based on £100k of internal staff costs plus £440k consultancy and external legal spend. While we use this as an estimate for likely costs under a TCLC investigation, it should be noted that this is likely to indicate an absolute upper limit for the cost for an investigation under the proposed TCLC, as a TCLC investigation is likely to be more targeted and hence less costly than a CA98 investigation. Another important factor is that investigations are likely to vary in length and complexity, and investigations that are closed down at a relatively early stage are likely to be significantly less costly still. Ofgem do not have data on such costs for industry, but assume that industry's investigation costs would be of a similar level to their costs, so we assume these would also be £540k per investigation.
52. Ofgem have put forward the following sensitivities for numbers of investigations:
- Low: 100% compliance from the start, in which case only preliminary investigations would be required and there would be no requirement for any full investigations (nor appeals to the CAT).
 - Central: one investigation in the first two years followed by no investigations in subsequent years due to full compliance with the licence provisions. After testing the boundary of the new condition, we anticipate that all generators would ensure their behaviour was compliant.
 - High: one investigation every two years on average for the duration of the TCLC; however, the length is likely to vary and this would include preliminary investigations that are closed early without action.
53. Table 4 below summarises investigation costs to Ofgem and business under the different scenarios. Under the counterfactual, we assume no investigation or appeal costs. Based on Ofgem's experience with the CA98 investigation into SP and SSE, we believe there is a low chance that Ofgem would attempt another investigation into similar behaviour in the wholesale market under CA98 powers.

Table 4 Investigation costs under Option 1, present value (£m)

	Ofgem	Business	Total
Low	0.0	0.0	0.0
Central	0.5	0.5	1.0
High	1.1	1.1	2.3

Source: Ofgem, DECC analysis. Note: figures may not add up due to rounding.

Appeal costs

54. Appeal costs will depend on a number of factors linked to, for example, the novelty and complexity of the points arising in case, the complexity and amount of evidence, and the number of parties involved.
55. Ofgem state that whilst the appeal costs to the Competition Appeals Tribunal (CAT) will also vary on a case-by- basis, they consider that a reasonable benchmark would be £250k to £600k where no external law firm is instructed and £500k to £1.2m where an external law firm is engaged. As with investigations, they expect industry to face a similar cost structure for appeals.
56. Evidence on costs in other types of appeals suggest that these estimates cover a reasonable range, and that the higher end probably represents an absolute ceiling for costs:
- In an IA introducing an appeals process for Ofgem licence modifications¹⁴, we estimated that an appeal on a licence modification would cost Ofgem £600k. This was based on experience of Ofgem's costs in relation to a recent code modification appeal which used external legal resource. E.ON UK have advised us that their external legal costs for their appeal to the CC under Section 173 of the Energy Act 2004 in 2007 were £257k. Other evidence provided in confidence suggests that companies may spend around £175k per appeal. These cost estimates may, however, not include internal costs of time. SSE, responding to the main consultation on GB implementation of the EU Third Package, suggested that costs could be in the range of £0.5m to £1m
 - Evidence from telecoms appeals suggests that £315k may be representative of industry spending on an appeal to the CAT.
57. Ofgem consider that one case going to appeal once over the period that the proposed TCLC is in place (5-7 years) seems a reasonable assumption. This is because the TCLC is intended to act as a deterrent, and therefore after testing the boundary of the new condition, we anticipate that all generators would

¹⁴ <http://www.decc.gov.uk/assets/decc/Consultations/eu-third-package/1161-ia-third-package-licence-mods.pdf>

ensure their behaviour was compliant. As it is not possible to predict in advance when an appeal would take place, Ofgem assume that the costs are incurred in the first year.

58. The CAT advise that, based on past experience with cases involving complex regulatory issues, they would expect CAT costs to be in the range of £30k-100k. We regard a mid-point in that range of £65k as being an appropriate central estimate¹⁵.
59. Table 5 below summarises appeal costs to Ofgem, business and the CAT under the following scenarios:
- Low: 100% compliance from the start; no appeals to the CAT;
 - Central: one appeal in the first year, costing £600k each to Ofgem and the appellant (toward the middle of the range of estimates suggested by Ofgem – see paragraph 54 above) and £65k to the CAT; and
 - High: one appeal in the first year, costing £1.2m each to Ofgem and the appellant (the high-end of the range of estimates suggested by Ofgem) and £100k to the CAT.

Table 5 Appeal costs under Option 1, present value (£m)

	Ofgem	Business	CAT	Total
Low	0.0	0.0	0.0	0.0
Central	0.5	0.5	0.1	1.1
High	1.1	1.1	0.1	2.3

Source: Ofgem, CAT, DECC analysis.

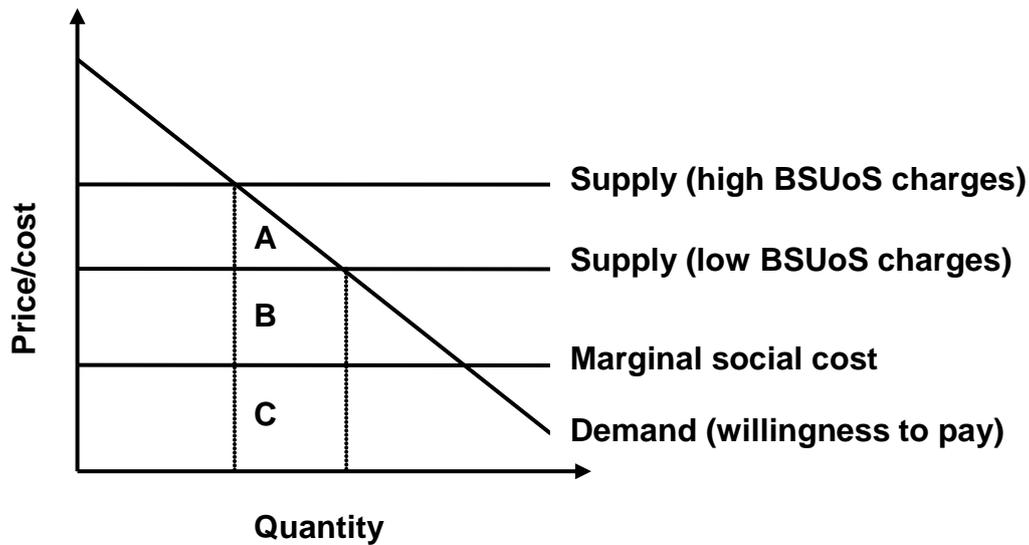
Monetised benefits

60. As a result of a reduction in constraint costs (see “Distributional Impacts” section below), there will be a reduction in retail electricity prices, due to lower BSUoS charges. Lower retail prices should lead to a slight increase in electricity consumption, to the extent that consumption is responsive to prices. This should lead to an overall welfare gain: the value that consumers are willing to pay for the increased consumption, as embodied by the retail electricity price, is greater than the increased resource costs (including traded sector emissions) from (slightly) increased consumption of electricity.
61. Economists term this a reduction in “deadweight loss”. The fall in BSUoS charges can be thought of as being similar to a reduction in tax on electricity: there is a reduction in the “wedge” between what society is willing to pay for electricity and the social costs of producing that electricity. It is unlikely that the fall in BSUoS charges would, by itself, result in a complete equalisation of retail prices and the marginal social cost of producing electricity.
62. Figure 4 below provides a simple illustration of the calculation. In summary, the welfare gain is calculated as the increase in “gross consumer surplus” (broadly, the increase in consumption multiplied by the retail price of electricity, represented by area A+B+C), less the increase in the marginal social costs¹⁶ of producing the electricity (represented by area C). The net welfare gain to society is represented by area A+B.

¹⁵ Note this is much smaller than estimated appeal costs to the CC contained in DECC’s IA for a Licence Modifications Appeals process under the EU Third Package. The CAT advise that, as a general principle, the cost to the CAT is likely to be substantially cheaper than the cost to the CC. That is because the number of members engaged on the case will be less (3 in the case of the CAT as opposed to, say 5 or more in the CC) and the CAT does not require a large staff team of experts to support the members.

¹⁶ This includes the variable costs of producing electricity; the costs of purchasing carbon allowances; and air quality damage costs.

Figure 4 Welfare gain from the TLC (reduction in deadweight loss)



63. The calculations of reduction in deadweight loss are based on the following central assumptions:

- Own-price elasticity of demand¹⁷ for electricity of -0.1 for both households and business consumers¹⁸;
- GB final electricity consumption based on DECC’s central Updated Emissions Projections (UEP), June 2010 (Annex C)¹⁹, adjusted for Northern Ireland’s share of UK electricity demand²⁰ in 2010; and
- Central variable supply costs, retail prices, marginal emissions factors, traded sector carbon values and air quality damage costs from the Interdepartmental Analysts’ Group (IAG) Toolkit²¹.

64. Retail price reductions are calculated by dividing the reduction in constraint costs (see Table 18) by GB electricity consumption. The estimates of the welfare gain (“reduction in deadweight loss”) are shown in Table 6 below, for different scenarios of constraint cost reductions (and corresponding changes in the retail electricity price), given the central elasticity assumptions. In addition, Table 6 shows how benefits can be attributed to households’ and business’ increases in consumption respectively.

Table 6 Reduction in deadweight loss under Option 1 (£m, present value) – sensitivity to different scenarios of constraint cost reductions (central elasticity assumptions)

	Households	Business	Total
Redpoint C&M Low	1.2	2.2	3.3
Redpoint C&M Central	2.3	4.1	6.3
Redpoint C&M High SG	3.6	6.7	10.4

Source: Table 18, DECC analysis. Note: figures may not sum due to rounding.

65. As well as differences in price changes, estimates of the reduction in deadweight loss are sensitive to elasticity estimates. We assume low, central and high price elasticities of demand of zero, -0.1 and -0.5 respectively.

66. There is a range of evidence to suggest that own-price elasticity of demand, while small in magnitude, is non-zero. According to recent estimates within the DECC energy model (using data from 1980 to 2006), long-run price elasticities for electricity are -0.14 and -0.1 for households and industrial users respectively. The DECC Energy Model suggests a zero electricity price elasticity for both households and industry in the short term (less than one or two years). However, we feel long-term price elasticities are more appropriate for the cost-benefit analysis central case. While price reductions will vary

¹⁷ “Own-price elasticity of demand” is a measure of the responsiveness of demand for a good to changes in the good’s price. An elasticity of X means that a 1% increase in the good’s price leads to an X% increase in demand for the good.

¹⁸ See paragraph 60 for more detail on elasticity assumptions.

¹⁹ <http://www.decc.gov.uk/assets/decc/Statistics/Projections/50-annex-c-final-energy-demand-.xlsx>

²⁰ DECC Energy Trends TABLE 5.5, “Availability and consumption of electricity”

http://www.decc.gov.uk/assets/decc/statistics/source/electricity/et5_5.xls

²¹ http://www.decc.gov.uk/assets/decc/Statistics/analysis_group/81-iag-toolkit-tables-1-29.xls. Note that this is consistent with DECC’s UEP June 2010.

somewhat from year to year, there will be a general reduction in prices, over a period of at least 5 years, as a result of the TCLC. For completeness, we test below a sensitivity with zero price elasticity.

67. For comparison, the Cambridge Econometrics (CE) and Oxford Economics (OE) models use an overall long run all-fuels elasticity for industrial energy consumption of -0.2 and -0.5 respectively – although they might be higher for some sectors. CE and OE use a residential energy price elasticity of -0.3 and -0.1 respectively, although the former has recently undertaken the analyses for the Green Fiscal Commission using an elasticity of -0.17.
68. Table 7 below shows the sensitivity of estimates of reduction in deadweight loss to different elasticity estimates, in the “Redpoint C&M Central” scenario.

Table 7 Reduction in deadweight loss due to the TCLC (£m) - sensitivity to different elasticity assumptions (Redpoint C&M Central)

	Households	Business	Total
Zero	0.0	0.0	0.0
Central (-0.1)	2.3	4.1	6.3
High (-0.5)	11.3	20.4	31.6

Source: Table 18, DECC analysis. Note: figures may not sum due to rounding.

Non-monetised impacts

69. In general, we believe non-monetised impacts will be relatively small in magnitude. While it may be possible to quantify impacts on returns to investors and existing generators under Option 1, this would be difficult. In the interests of proportionality, therefore, we discuss only qualitative points below.

Set-up and monitoring costs

70. We consider these costs to be negligible. Ofgem already monitor generator behaviour in wholesale markets, and consider it unlikely that they would incur significant additional day-to-day costs in administering the proposed TCLC. Likewise, given the TCLC is intended to draw on, but be distinct from, the prohibitions established under CA98, industry should already have in place compliance procedures that could, without significant additional cost, be adapted to encompass the proposed TCLC. In addition, generators already actively monitor and retain data on the key inputs to the analysis that would be required to determine any breach of the proposed TCLC – such as spreads available in the GB wholesale market, plant efficiencies, fuel costs and other avoidable costs – for commercial reasons. Hence, Ofgem advises us that these costs to business would be minimal.

Effect on investment

71. A reduction in the level and volatility of BSUoS charges relating to constraint actions, as a result of Option 1, would reduce costs to all market participants. This should reduce barriers to investment, especially for smaller participants, who are less able to manage such charges.
72. To the extent that the costs of constraint actions, and hence constraint-related exploitative behaviour, may feed through into the cash-out price²² via “system pollution” – thus making the cash-out price unduly penal – Option 1 could yield positive impacts for small new entrant and/or intermittent generators (who are more likely to be out of balance and therefore face cash-out charges. Balancing and Settlement Code (BSC) Modification Proposal P217A, implemented in November 2009, introduced a revised “tagging” process for “system balancing” actions²³. Following this, constraint-related costs should not have a significant impact on cash-out prices. However, to the extent that the tagging mechanism remains

²² “Cash-out” arrangements are designed to target the cost of “energy balancing” (ensuring that GB-wide demand equals GB-wide generation) incurred by National Grid to the parties who created those costs (i.e. those parties who do not balance their inputs and outputs within the relevant balancing period). As such, parties who are not in balance incur charges that reflect the costs incurred by National Grid in addressing the imbalance. These charges are known as “cash-out” prices.

²³ “Energy balancing” refers to actions taken by National Grid purely to resolve an overall supply-demand imbalance on the system; “system balancing” refers to actions taken for specific reasons such as to resolve transmission constraints. The “tagging” process is meant to ensure that cash-out prices are reflective of the costs of energy balancing only.

imperfect, constraint costs may still feed through to cash-out occasionally²⁴. These costs would therefore unduly impact on those parties that are out of balance in the periods in which exploitation occurs, which could deter investment at present.

73. However, reduced BSUoS charges are the direct result of falls in revenue for some generators. The impact on levels and certainty of revenues under Option 1 will vary across generators. For example, if it is the case that flexible generators located in constrained areas are most able to manipulate output, then the returns to flexible generation will fall relative to returns to inflexible generation (e.g. wind, nuclear). However, under Option 1, there will be no restrictions on pricing or withholding behaviour in the wider wholesale market, and restrictions on pricing behaviour will be focused on generators in export-constrained regions only. We therefore do not expect a significant deterrent effect on new investment under the Option 1 and have not attempted to quantify this impact. For similar reasons, it is anticipated that the introduction of Option 1 will not increase the cost of capital for all plant.
74. Overall, given the likelihood of small offsetting positive impacts (due to reduced cash-out and BSUoS levels and volatility) and negative impacts (due to reduced returns to some plant in constrained regions), we consider there would be a negligible net impact on investment under Option 1.

Effects on existing peaking plant operation

75. In the electricity market, the normal cycle of investment is for new entry at baseload (i.e. running at high load factors). This typically means more efficient plant displaces less efficient plant, which then runs at progressively lower load factors until it becomes “peaking” plant. Plant may be fully written down by the time they are acting as peaking plant. Therefore, provided prices are sufficiently high to cover the avoidable costs of staying on the system, they should continue to run.
76. It is however possible that non-exploitative bidding, combined with restrictions on “non-economic dispatch”, might lead to early closure of some peaking plant in export constrained areas (i.e. Scotland). However, in most cases, any plant that might be affected are already scheduled to retire or reduce capacity in the near future²⁵. Therefore, the impacts are likely to be minimal. Finally, it should be noted that currently export-constrained regions are also forecast to experience substantial growth in inflexible wind generation in future years, and as such even if flexible thermal plant in these areas remain on the system they are likely to be “bid back” in the BM ever more frequently over time (i.e. they will not actually physically run during export constrained periods because of the excess of generation capacity in Scotland relative to the transmission capacity over the boundary into England & Wales). This reinforces the view that early retirement of such plant is unlikely to lead to any material change in security of supply.
77. Overall, we consider that any incremental impact of Option 1 in terms of accelerating early closure of thermal plant in Scotland is likely to be minimal, and have not attempted to quantify this impact.

Impact on future constraint costs

78. Option 1 should reduce the incentive to invest in or schedule plant in export-constrained areas, by restricting pricing behaviour during export constraints. This will tend to result in lower future (i.e. after the expiry of the TCLC) constraint volumes, and therefore costs, than would have otherwise been the case.
79. However, the impact, while positive, is likely to be small (as argued above). Constraint payments will generally be a small component of overall revenues for a power plant. To an extent, incentives for efficient locational investment decisions are already provided by the locational element in the Transmission Network Use of System (TNUoS) charges for generators.

Option 2

80. Option 2 is as Option 1 above, but would also prohibit exploitative offers when an import constraint is active.

²⁴ Ofgem is currently seeking views on whether it should conduct a significant code review (SCR) considering reforms to electricity imbalance pricing or ‘cash-out’. It is also seeking views on the issues around cash-out and the scope of a potential SCR, including issues of “system pollution”. See:

<http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=148&refer=Markets/WhIMkts/CompanEff/CashoutR>

²⁵ For example, approximately 9GW of coal plant “opted out” under the Large Combustion Plant Directive (LCPD) will have to close by 2015 at the latest.

Monetised costs and benefits

81. The vast majority of constraint costs have historically been, and are expected in the medium-term to continue to be, associated with export constraints. So we believe that investigation and appeal costs under Option 2 could be higher than costs under Option 1, though the difference would likely only be marginal, given that there would not be many potential additional cases of exploitative behaviour to investigate. Likewise, constraint cost reductions might be higher, but only by a little bit, and the impact on reduction in deadweight loss would be even smaller. Given this, we have not quantified the difference in monetised costs and benefits between Options 1 and 2, but simply assume that monetised costs and benefits would be the same as Option 1.

Other impacts

Impact on investment

82. To the extent that Option 2 results in greater constraint cost reductions than Option 1, BSUoS charges will be reduced further, while returns to flexible plant will fall further (only plant with ability to increase generation would be affected by restriction on pricing of “offers”).

Impact on existing peaking plant operation

83. Option 2 would also contribute to accelerated closure of peaking plant, above Option 1, by further reducing returns to flexible plant.

Impact on future constraint costs

84. Option 2 would reduce the incentive to build new or schedule existing plant in import-constrained regions, where new generation would be most needed. This would, in turn, tend to exacerbate the problem of import constraint costs in the longer-term (i.e. after the expiry of the TCLC), by reducing competitive pressure on generators in an import-constrained region, relative to Option 1. As discussed under Option 1, this impact would likely be small in magnitude.

Option 3

85. Option 3 is as Option 2 above, but would also contain a general condition, prohibiting any other circumstances where generators are able to obtain “excessive benefits” in relation to an increase or decrease in generation during a transmission constraint period.
86. Option 3 has the potential to deliver additional benefits to society and consumers above Options 1 and 2 through additional constraint cost reductions, although this is uncertain in the absence of specific behaviours to be targeted by the general condition, and hence we have not attempted to quantify this impact. In addition, Option 3 could entail additional administrative costs, while creating additional uncertainty for investment and blunting signals to invest in import-constrained regions.
87. We are consulting on whether there are specific types of exploitative behaviour not captured by the prohibitions under Option 1. Therefore, at this point, it is difficult to be specific on the costs and benefits of Option 3.

Costs

88. Ofgem have currently not identified specific circumstances in which they would use either this general condition or other specific conditions, although including additional conditions would give Ofgem scope to tackle other forms of exploitative behaviour during transmission constraints that could arise in the future. Given this, we believe that investigation and appeal costs under Option 3 could be higher than costs under Options 1 and 2. In the absence of any further evidence, we have not quantified this impact.

Benefits

89. Depending on what it was used for, benefits to society (and to consumers) could be greater than Option 1, due to the general widening of scope to reduce constraint costs. We do not currently have strong evidence of other behaviours that could be prohibited by the general condition, and hence we have not tried to quantify this impact. A general condition would, however, give Ofgem flexibility to tackle other forms of exploitative behaviour during transmission constraints that could arise in the future.

Other impacts

Impact on investment

90. To the extent that Option 2 results in greater constraint cost reductions than Option 1, BSUoS charges will be reduced further, while returns to flexible plant will fall further (only plant with ability to increase generation would be affected by restriction on pricing of “offers”).

91. A general condition could significantly increase the regulatory risks faced by companies, with resulting negative effects on investment. In particular, a general condition would increase Ofgem’s discretion and the scope for subjective decision making. Companies would not know at the point in time of making (e.g. bidding) decisions what market outcomes will be and how their behaviour would be judged by Ofgem ex-post. We prefer specific conditions targeting particular exploitative behaviours.

Impact on existing peaking plant operation

92. Option 2 would also contribute to accelerated closure of peaking plant, above Option 1, by further reducing both levels and certainty of returns to flexible plant.

Impact on future constraint costs

93. In the absence of specific behaviours to be prohibited, enforcement action may be less credible, which may make it more difficult to reduce market manipulation.

Distributional impacts

94. This section considers the distributional impacts of Option 1, including:

- Reduction in constraint costs (benefits to consumers); and
- Net direct costs to business.

Reduction in constraint costs

95. Implementation of the TCLC will reduce constraint costs due to the exploitation behaviour during constraint periods. As described above (see “Background” section), constraint costs are paid for ultimately by GB consumers. The Annex goes into more detail on:

- drivers of constraint costs;
- projections of constraint costs; and
- How we estimate the reduction in constraint costs arising from Option 1.

96. Different scenarios for the estimated reduction in constraint costs due to TCLC (Option 1) are shown in Table 8 below.

Table 8 Estimated constraint cost reductions from the TCLC (Option 1) (£m)

	2013	2014	2015	2016	2017	Present Value
Redpoint C&M Low	50.8	39.5	32.7	3.2	5.3	114.5
Redpoint C&M Central	78.9	73.2	84.9	7.8	8.8	219.7
Redpoint C&M High SG	85.7	71.6	91.3	101.2	63.0	298.8

Source: Table 18

97. In the “Redpoint C&M Central” scenario, based on simply dividing the estimated reduction in constraint costs by GB electricity consumption, average reductions in retail prices for electricity consumers could be £0.16/MWh over 2013 to 2017. For a domestic consumer, based on retail prices from the IAG Toolkit²⁶, this is equivalent to an average 0.12% reduction in retail prices, or a £0.70 reduction in the annual electricity bill, based on average annual consumption of 4.4MWh.
98. This analysis assumes that reductions in BSUoS charges are spread equally amongst all types of consumers. Depending on the year and scenario, the reduction in price in could vary anywhere between £0.01/MWh and £0.31/MWh.

Net direct costs to business

99. The section above (“Cost-benefit analysis”) discusses cost and benefits to society at large, including business, from Option 1. For the purposes of one-in, one-out (OIOO), we believe the following would be considered direct costs and benefits to business only:

- Direct cost to generators, who lose profit as a result of implementation of a TCLC, exactly offset by a direct benefit to National Grid, whose constraint payments are lowered as a result of the TCLC;
- Direct costs to generators associated with investigations by Ofgem into whether a breach of the licence condition has occurred; and
- Direct costs to generators associated with appeals against enforcement orders;

²⁶ http://www.decc.gov.uk/assets/decc/Statistics/analysis_group/81-iag-toolkit-tables-1-29.xls. Note that this is consistent with DECC’s UEP June 2010.

- Direct benefits to businesses associated with the “reduction in deadweight loss”. This benefit arises since:
 - Lower retail prices result in some increase in electricity consumption; and
 - At the margin, the amount business consumers are willing to pay for this extra consumption (gain in consumer surplus) is higher than the costs (to other businesses) of supplying the increased consumption of electricity. We consider this to be a “direct” impact, since it is a first-order welfare impact of the introduction of the TCLC.

100. For the purposes of OIOO, we view all investigation costs as direct costs to business. With respect to appeal costs, costs would be considered direct only if the generator in question appealed against an enforcement order and was found by the CAT not to be in breach of the TCLC. If this were the case, and the generator appealed successfully, it is likely that the CAT would award the generator any reasonable costs incurred as a result of the appeal. We thus assume that there are no direct costs to generators associated with appeals.

101. Table 9 below summarises the range of estimates for net direct costs to business under Option 1. Estimates of benefits from increased consumption are based on the methodology described in paragraphs 60 to 65 above (adjusting for business’s proportion of increased consumption).

Table 9 Present value of net direct monetised costs to business under Option 1 (£m)

	Costs	Benefits	Net costs
Low	0.0	21.1	-21.1
Central	0.5	4.2	-3.7
High	1.1	0.0	1.1

Source: Table 4, Table 7, DECC analysis. Note: direct benefits to business are based on estimates presented in Table 7, but are marginally higher, since they exclude the costs of air quality damages, which are not borne directly by business.

102. Based on the central estimates in Table 9 above, there is a net benefit to business of £4.0m (present value) arising from the TCLC proposals. The central estimate of Equivalent Annual Net Cost to Business (EANCB) is £-0.9m (per annum). Table 10 below presents the full range of EANCB estimates from the TCLC.

Table 10 Equivalent annual net direct monetised costs to business under Option 1 (£m)

	Costs	Benefits	Net costs
Low	0.00	4.5	-4.5
Central	0.10	0.9	-0.8
High	0.24	0.0	0.2

Source: Table 9, BRE EANCB calculator.

Risks and assumptions

103. Monetised estimates of costs, benefits and distributional impacts above are dependent on a number of assumptions (for example, on number of appeals, number of investigations, and “baseline” constraint costs). These assumptions are discussed in more detail above.
104. We also implicitly assume that the licence condition is effectively enforced by Ofgem. However, it is possible that it may be difficult to enforce, in which case benefits might be low and/or enforcement costs might be high. We believe the sensitivities presented above around the level of costs and benefits are essentially already capture this range of possible outcomes. In its consultation on the draft Guidance for the TCLC, Ofgem is consulting on the details of implementation and enforcement. We anticipate that responses to Ofgem’s consultation will inform the Final IA.

Specific impact tests

Competition impacts

105. While the TCLC would not directly affect the number of wholesale or retail electricity market participants, it might have some indirect impacts. To the extent that it reduces BSUoS charge or cash-out price volatility, it may reduce barriers to entry for both new generators and suppliers, which may be less well-placed to manage this risk, compared to larger players.
106. The TCLC will result in some restrictions on generators’ ability to price in offering constraint reduction services to National Grid, which could be seen as detrimental to competition. Ofgem are consulting on

the details of implementation, including indicators that a generator may have benefited excessively from its actions. It is important to note that any restrictions on pricing will only apply to periods of transmission constraint, and not to pricing in the wider wholesale market. As discussed in the “Problem under Consideration” section above, the TCLC is intended to apply to situations in which new entry is unlikely to lead to a lowering of costs to consumers, due to significant barriers to entry.

107. The TCLC does not replace existing competition law: it is intended to complement existing competition legislation.

Microbusiness impacts

108. Microbusinesses are defined as those businesses with fewer than 10 employees. As discussed above, the directly affected businesses are National Grid and some electricity generators. National Grid is not a microbusiness, but a small number of generators might be.
109. We believe that thermal (i.e. gas/coal) generators are, in general, not owned by microbusinesses. However, some wind farms may be. Directly affected wind farms would include those with very high bids accepted in the BM. Initial analysis of the wind farms with high bids accepted in 2011 so far suggests that most, if not all, of these are owned by larger parent companies that would not be microbusinesses.
110. Given this, the impact of a microbusiness exemption would have limited benefit. It could potentially also increase costs for Ofgem, if it has to ascertain whether a generator licensee is a microbusiness. To the extent that generator microbusinesses would gain from an exemption, electricity consumers (including microbusinesses, individuals and other businesses) would lose.
111. As part of our consultation, we will be examining further the impacts of the proposals on microbusinesses.

Equalities

112. We do not consider that the impact of our proposals is likely to differ, on account of any of the protected characteristics (age, disability, gender reassignment, marriage and civil partnership, pregnancy and maternity, race, religion or belief, sex or sexual orientation).

Human Rights

113. To the extent that human rights may be engaged, we consider the approach to be compatible with the Human Rights Act 1998.

Greenhouse gas impacts

114. Due to the small increase in electricity consumption, there will a small increase in UK purchases in carbon allowances. This is already accounted for in the monetised estimates of costs and benefits above. Table 11 below presents the impact on purchases of carbon allowances, based on different elasticity assumptions, but assuming electricity price reductions consistent with the “Redpoint C&M Central” scenario.

Table 11 Impacts on purchases of carbon allowances (MtCO₂e)

	2013	2014	2015	2016	2017	Total
Zero elasticity	0.00	0.00	0.00	0.00	0.00	0.00
Central elasticity (-0.1)	0.02	0.02	0.02	0.00	0.00	0.09
High elasticity (-0.5)	0.10	0.09	0.10	0.01	0.01	0.31

Source: DECC analysis

Post-implementation Review

115. The Energy Act 2010 sets out a sunset clause that means the TCLC can only be in place for a maximum of 7 years – an initial 5 year period that may be extended by 2 years, following a review, through secondary legislation. Towards the end of the initial 5 year period we will review the policy to assess whether the licence condition should be extended by 2 years, basing this assessment on its effectiveness and the costs and benefits of extending it.

Annex A – estimating reductions in constraint costs from the TCLC (Option 1)

116. Implementation of the TCLC will reduce constraint costs that arise due to exploitative behaviour during constraint periods. As described above (see “Background” section), constraint costs are paid for ultimately by GB consumers. This section:

- Discusses drivers of constraint costs;
- Compares projections of constraint costs; and
- Estimates the reduction in constraint costs arising from the proposals.

Drivers of constraint costs

117. Constraint costs are a product of constraint volumes (i.e. the volume of actions that National Grid needs to take to resolve constraints) and the price of actions taken by National Grid to resolve constraints. Exploitative behaviour can increase constraint volumes (e.g. because of output manipulation) and the price of constraint actions (through pricing behaviour).

118. Constraint volumes depend on several drivers, other than exploitative behaviour. Table 12 below summarises some of the drivers of constraint volumes and costs.

Table 12 Summary of drivers of constraint volumes and costs

Driver	Likely impact on constraint costs
GB transmission infrastructure build	Generally will result in a fall in constraint volumes, through easing congestion. However, constraints may increase during maintenance work.
Increased generation build	Ambiguous. Could result in an increase in constraint volumes, especially if new plant built in constrained regions (e.g. wind in Scotland). However, it could result in lower constraint prices, to the extent competition in balancing services markets is increased.
Fossil fuel prices	Ambiguous. But possible that higher relative coal generation costs could lead to Scottish coal plant being constrained off less.
More interconnection	Ambiguous. Could either exacerbate import constraints or relieve export constraints. Could reduce constraint prices, by improving competition in balancing services markets, through effectively allowing foreign generators/consumers to offer balancing services to National Grid.
Sharper locational differential in network charges	Generally will result in a fall in constraint volumes, through incentivising lower dispatch/reduced investment in export-constrained regions, relative to other (including import-constrained) regions.
Higher electricity demand	Generally will tend to increase constraint volumes, by increasing the number of occasions when transmission constraints bind. However, the impact will depend on the location of increased demand.
Other environmental policy	Ambiguous. Air quality policies such as the Industrial Emissions Directive (IED) may lead to early closure of fossil fuel plant, or limits to running hours, if generators choose not to meet emissions limits by installing emissions abatement equipment. Could result either in a fall in Scottish export constraint volumes, or an increase in import constraint volumes (at times of low wind generation).

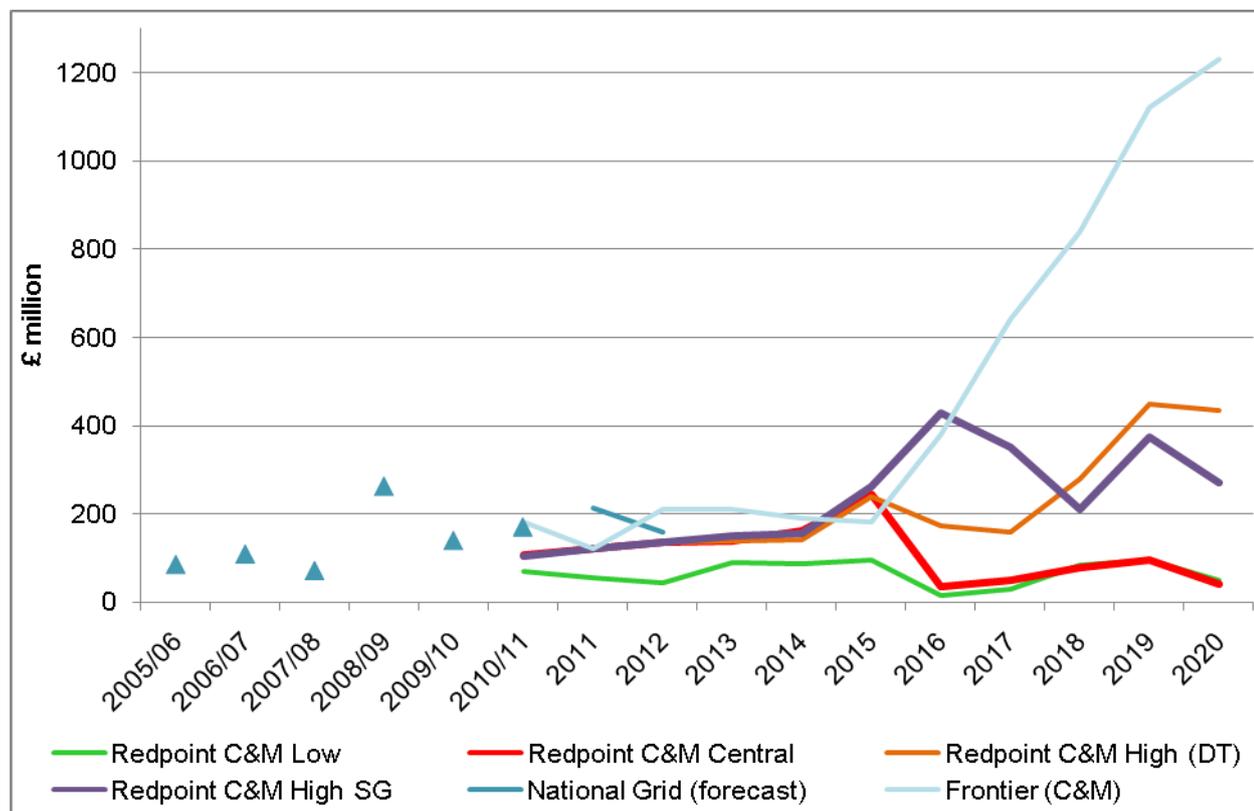
Comparison of constraint costs projections

119. Modelled projections of constraint costs generally assume economic dispatch behaviour. In addition, they tend to assume bidding premia/discounts (relative to short-run marginal cost) in the BM based on

historical data, which may include some element of exploitative pricing. Assumptions on various constraint cost drivers (see above) may also vary.

120. Figure 5 below compares recent estimates of future constraint costs. All estimates assume the implementation of an enduring “Connect and Manage” (C&M) transmission access regime, with National Grid smearing incremental constraint costs equally across all market participants. The Frontier Economics (“Frontier”) and Redpoint estimates were prepared in 2010 (for Ofgem and DECC respectively) in the context of the Transmission Access Review (TAR) work. National Grid’s estimates are shorter-term, since they were carried out for the purposes of its 2011-2013 System Operator (SO) incentives.

Figure 5 Constraint cost estimates - different models and scenarios



Sources: National Grid, Redpoint, Frontier.

121. As can be seen above in Figure 5, there is a wide range of constraint cost estimates, especially from about 2015 onwards. Redpoint’s central (and low) estimates fall from about 2015, as new transmission investment in Scotland (onshore reinforcement plus the Western DC link) comes online. In the High Scottish Generation (SG) scenario, this fall is delayed reflecting the two year delay in all reinforcements. In the High Delayed Transmission (DT) scenario, reinforcements are delayed until after 2020, so there is no fall evident in Figure 5. Frontier’s estimates are significantly higher, primarily because, compared to Redpoint, Frontier assumes higher renewable (primarily wind) investment both overall in GB (and particularly in Scotland) and no transmission reinforcements post-2015 to the B1 boundary (between Northern and Southern Scotland).

122. The Redpoint and Frontier estimates were carried out before the Government’s Electricity Market Reform (EMR) White Paper, and so do not account explicitly for the impact of any EMR policies on electricity generation and investment, or on plant bidding behaviour in the BM. However, EMR policies are only likely to start having a significant impact on investment in the late 2010s, around which time the TCLC’s sunset clause would come into effect.

Valuing Reductions in constraint costs

123. The previous sub-sections highlight the uncertainty over future constraint costs. Clearly, though we believe that the TCLC will contribute to lower constraint costs, there is uncertainty in estimating precise reductions in future constraint costs as a result of TCLC. We take the following approach, which is intended to provide a suitable range of estimates of consumer benefits from the TCLC:

- Step 1: Select a range of modelled estimates of future constraint costs, which assume economic dispatch.

- Step 2: Apply an uplift to constraint costs, reflecting the exploitative pricing behaviour during export constraints
- Step 3: Apply another uplift to constraint costs under Step 2, reflecting the increase in constraint volumes due to non-economic dispatch
- Step 4: The estimated reduction in constraint costs due to TCLC is the difference between constraint costs under Step 3 and Step 1.

124. There is much uncertainty in the exact constraint reductions that the TCLC will deliver, as this depends partly on generators' reactions to the proposed licence condition. We assume here that the TCLC is effectively implemented. However, we consider that, in using a wide range of estimates for future constraint costs, we capture a large degree of the uncertainty over the effectiveness of the TCLC.

Step 1 – selecting projections of constraint costs

125. We base our estimate of constraint cost reductions on the following three Redpoint scenarios:

- Redpoint C&M Low;
- Redpoint C&M Central; and
- Redpoint C&M High SG.

126. We select Redpoint's analysis (over Frontier's), as DECC believes the central assumptions on transmission and renewables investment are more reasonable²⁷. Using Redpoint's range of constraint cost estimates is also likely to lead to a more conservative estimate of constraint cost reductions, compared to the larger Frontier estimates above.

127. Table 13 below shows the modelled constraint costs under the three scenarios outlined above.

Table 13 Modelled constraint costs under different scenarios (£m)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Redpoint C&M Low	67.7	53.9	42.1	88.6	85.7	93.8	13.7	29.2	81.3	92.7	47.9
Redpoint C&M Central	104.1	120.8	135.2	137.7	158.8	243.8	33.1	48.8	75.7	93.7	38.8
Redpoint C&M High SG	104.1	120.8	135.2	149.5	155.4	262.0	428.9	350.5	211.5	372.9	272.0

Source: Redpoint

Step 2 – accounting for pricing behaviour in export constraints

128. There will be a benefit to consumers from restricting pricing by export-constrained generators. Ofgem's consultants on the TAR project, Frontier, carried out in 2009 a forward-looking analysis of constraint costs out to 2017/18 under different types of bid/offer behaviour in the BM²⁸. Ofgem used the Frontier modelling as the basis for estimates of the impact on export constraint cost savings to consumers from implementing the export-constraint pricing restrictions under the TCLC. This analysis effectively assumed that the TCLC was implemented in 2010/11.

129. For the counterfactual case, against which the proposals were assessed, Ofgem used Frontier's "Ofgem Market Power" scenario in which balancing mechanism (BM) bids and offers are priced at observed mark-ups/mark-downs to Short-Run Marginal Cost (SRMC). This was assessed against a "cost recovery" scenario, in which all generators bid at short-run marginal cost for bids and long-run marginal cost (LRMC) for offers.

130. This does not exactly match the proposals (in which export-constrained generators essentially have their bids related to avoidable costs, while offer prices²⁹ in import constraints are uncapped and hence will be set by market competition and may be either higher or lower than LRMC). However, it provides a good approximation, since the majority of constraint volumes are associated with times of export constraint.

131. Table 14 below shows the results of this earlier Frontier modelling.

²⁷ Frontier's analysis assumed much higher renewables investment, particularly in the North of Scotland, and less transmission build.

²⁸ Note: this analysis preceded that presented in Figure 3 above. In particular, it does not assume any acceleration in either generation or transmission investment, for example due to implementation of a Connect & Manage regime for transmission access.

²⁹ "Bids" refer to the price quoted by generators to reduce generation in the BM; "offers" refer to the price quoted by generators to increase generation in the BM.

Table 14 Annual Constraint Costs under “Ofgem Market Power” and “Ofgem Cost Recovery” scenarios (£m)

	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Ofgem Market Power	482.6	553.9	498.2	489.5	641.4	529.7	341.6	379.1
Ofgem Cost Recovery	271.3	332.1	318.4	335.0	491.7	389.4	298.5	343.8
Difference	211.3	221.8	179.8	154.6	149.7	140.3	43.2	35.2
% uplift over “Cost Recovery”	78%	67%	56%	46%	30%	36%	14%	10%

Source: Ofgem

132. It is difficult to apply the above uplift straightforwardly to the Redpoint estimates in Table 13 above, for the following reasons:
- The ability to exercise market power in constraint pricing may depend both on the underlying generation mix and constraint volumes in any given scenario.
 - In the Redpoint modelling, assumed bid-offer discounts and premia in the Balancing Mechanism (BM) are based on historical observations and hence may incorporate an element of exploitative pricing behaviour, although Redpoint did not differentiate the level of BM bids and offers based on the location of generation plant.
133. The fall in the “uplift” over time is likely driven by assumptions on plant closures and BM pricing behaviour. For example, if coal plants have high observed premia/discounts and some of these are due to close by 2015 under the LCPD, then this would result in a reduction in the uplift. It is important to note that the modelling assumed fixed bid discounts and offer premia over time. In reality, these might change with market conditions and with the changes in the generation mix.
134. Given that the Redpoint modelling suggests overall lower constraint volumes, and given that constraint pricing may already incorporate an element of exploitative pricing behaviour, we believe it is appropriate to apply somewhat lower uplifts than implied by Frontier’s modelling for Ofgem. We assume uplifts in 2013 to 2017 of 40%, 30%, 20%, 10% and 5% respectively.
135. Applying these uplift assumptions to the Redpoint projections gives the range of constraint cost estimates, including an uplift for export constraint pricing behaviour, shown in Table 15 below.

Table 15 Projected constraint costs, with uplift for export constraint pricing behaviour (£m)

	2013	2014	2015	2016	2017
Redpoint C&M Low	124.1	111.4	112.6	15.1	30.7
Redpoint C&M Central	192.8	206.5	292.6	36.4	51.2
Redpoint C&M High SG	209.3	202.0	314.4	471.8	368.1

Source: Table 13, Paragraph 134

Step 3 – accounting for non-economic dispatch

136. There will be a benefit to consumers from restricting “non-economic dispatch” (i.e. failing to dispatch in line with the spreads available in the GB wholesale market) for both import and export-constrained generators under the proposed TCLC.
137. In order to estimate this impact, Ofgem used data from National Grid, SP and SSE obtained under the CA98 investigation to calculate the proportion of Scottish import and export constraint volumes over 2006 to 2008 that could potentially have been attributed to non-economic dispatch. Ofgem then took the average proportion of constraint costs attributable to non-economic despatch from 2006-2008.
138. For export constraints, Ofgem assumed output was “non-economic dispatch” when a generator submitted an intention to run despite a negative spread in the within-day market (either <0 £/MWh [high case] or <-5 £/MWh [low case])³⁰. For import constraints, Ofgem assumed non-economic dispatch when

³⁰ Submission of an intention to generate (not generate) against any negative (positive) spread for an export (import) constraint could strictly speaking be defined as non-economic dispatch, and hence the use of 0 £/MWh as the “high case” for the estimated impact of non-economic dispatch. However, given that other factors that have not specifically been modelled (such as maintenance issues and environmental restrictions) may also impact on whether a dispatch decision is “economic” or not, we have also modelled a more conservative scenario using a negative (positive) spread threshold of 5 £/MWh.

a generator submitted an intention NOT to run despite a positive spread in the within-day market (either >0 £/MWh [high case] or >+5 £/MWh [low case]). In both cases, Ofgem calculated spreads for individual generators taking into account plant-specific characteristics such as the efficiency of conversion of fuel to electricity. While this particular definition of non-economic dispatch is somewhat narrower than that envisaged under Option 1, which would prohibit (during a transmission constraint period) dispatching or withholding one or more generation units in circumstances when the generator had more economic options available, it provides us with a reasonable estimate.

139. For both export and import constraints, Ofgem multiplied the ratio of non-economic dispatch volume to total constraint volume by the total constraint cost, to obtain an estimate of the proportion of constraint costs due to non-economic dispatch. The results from the historical analysis are summarised in Table 16 below.

Table 16 Proportion of Historic Scottish Constraint Costs Attributable to Non-economic Dispatch – weighted monthly average

	2006	2007	2008*	Overall average**
Export constraints				
Spread <-5	16%	1%	8%	11%
Spread <0	45%	43%	15%	35%
Import constraints				
Spread > 5	36%	71%	69%	68%
Spread > 0	61%	89%	69%	86%

Source: Ofgem Analysis. *Data for January to June only. **Weighted average of monthly data from January 2006 to June 2008.

140. We apply the 11% uplift to the projected costs in the Redpoint modelling, after adjusting for export pricing behaviour (as discussed above), since:
- Using a more restrictive (£5/MWh) spread threshold should result in a more conservative estimate of constraint cost reductions due to restricting non-economic dispatch behaviour; and
 - the majority of projected constraint costs are due to Scottish export constraints.
141. Table 17 below shows projected constraint costs, with both an uplift for export constraint pricing behaviour and non-economic dispatch behaviour.

Table 17 Projected constraint costs, with uplift for export constraint pricing behaviour and non-economic dispatch behaviour (£m)

	2013	2014	2015	2016	2017
Redpoint C&M Low	139.4	125.2	126.5	17.0	34.5
Redpoint C&M Central	216.7	232.0	328.8	40.9	57.6
Redpoint C&M High SG	235.1	227.0	353.3	530.1	413.6

Source: Table 13, Table 15, Paragraph 140

Step 4 – estimating the reduction in constraint costs

142. The estimated reduction in constraint costs due to TCLC (Option 1) is the difference between constraint costs in Table 13 and Table 17. This is shown in Table 18 below.

Table 18 Estimated constraint cost reductions from the TCLC (Option 1) (£m)

	2013	2014	2015	2016	2017	Present Value
Redpoint C&M Low	50.8	39.5	32.7	3.2	5.3	114.5
Redpoint C&M Central	78.9	73.2	84.9	7.8	8.8	219.7
Redpoint C&M High SG	85.7	71.6	91.3	101.2	63.0	298.8

Source: Table 13, Table 17