nationalgrid

CONSULTATION DOCUMENT

GB ECM-19

Charging for Large Loss Frequency Response

11 June 2010

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1 Executive Summary

The extant NETS SQSS (National Electricity Transmission System Security and Quality of Supply Standards) require[1] that the transmission system is planned on the basis of accepting a normal (i.e. relatively frequent) loss of power infeed of up to 1000MW, and an infrequent (i.e. in the region of up to four occurrences per year) loss of power infeed of up to 1320MW. The level of Response contracted by the System Operator is based on these levels of loss of power infeed. At present there are several new developments being considered that could result in frequent losses in excess of 1000MW and infrequent losses in excess of 1320MW.

The SQSS Review Group concluded in report GSR007[2] that the current SQSS planning criteria were not designed for the connection of large units (or large groups) with a total capacity in excess of 1320MW. In the event of new large units of capacity in excess of 1320MW being connected to the system, the Group recommended that the normal and infrequent loss limits in the NETS SQSS should be raised to 1320MW and 1800MW respectively, so as to remove a barrier to the timely connection and access of large generating units. It was identified by the SQSS Review Group that if a number of these large new generation units connect to the system, the estimated operational cost to the System Operator could rise from £160M per year to a level of £319M per year reflecting an increase in frequency response held. Primary frequency response is required to contain the instantaneous fall in frequency within ten seconds of a loss, whilst secondary frequency response is required to recover such a loss after ten seconds.

National Grid is obliged to keep the charging methodology under review at all times. Given the magnitude of this potential increase in operational costs, National Grid considers it appropriate to review the Use of System Charging Methodology and the charging arrangements for the recovery of Response services in particular.

The purpose of this consultation document is therefore to invite industry views on:

1. the analysis undertaken by National Grid on the three potential approaches to charging for response, including the assumptions, results and impacts

2. National Grid's initial conclusions and comparisons of each approach against the relevant objectives

Responses and queries should be sent to adam.sims@uk.ngrid.com no later than Friday 09 July 2010. All responses will be treated as non-confidential and published on the National Grid charging website unless they are clearly market otherwise.

This report has been published on the National Grid charging website:
http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/

[1] Sections 2 and 7 of the NETS SQSS: http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/DocLibrary/
[2] http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/reviews/

2 Introduction

As the National Electricity Transmission System Operator (NETSO), authorised to co-ordinate and direct the flow of electricity onto and over the transmission system within Great Britain, National Grid has duties under the Electricity Act to develop and maintain an efficient, co-ordinated and economical transmission system and to facilitate competition in generation and supply.

Along with these high level duties, National Grid is obliged under its transmission licence:

- to keep the Use of System Charging and Connection Charging Methodologies at all times under review

- to make such modifications of the Use of System Charging Methodology as may be requisite for the purpose of better achieving the relevant objectives, which are:

    a. to facilitate effective competition in generation and supply;

    b. to result in charges which reflect, as far as reasonably practicable, the costs incurred by transmission licensees in their transmission businesses;

    c. in so far as is consistent with a) and b) above, as far as reasonably practicable, to properly take account of the developments in transmission licensees' transmission businesses.

In addition to the relevant objectives above, condition C7 of the transmission licence also prohibits National Grid from discriminating against any User or class of Users unless such different treatment reasonably reflects differences in the costs of providing a service.

A pre-consultation was published in December 2009 which invited views from industry participants on the operation of the current charging arrangements in light of the increase in threshold limits proposed, and the consequential operational costs that may be incurred to accommodate larger units onto the transmission system. This consultation contains a summary of the pre-consultation and sets out the further analysis undertaken by National Grid to inform the assessment of the impact of any change to the charging arrangements.

3 Background

The Electricity Safety, Quality and Continuity (Amendment) Regulations 2006, Part VII, clause 27 (commonly referred to as the ESQCR)[3] requires that system frequency shall not vary more than 1% above or below the declared frequency of 50Hz save in 'exceptional circumstances'. The actual containment of frequency to within required limits is the subject of the NETS SQSS (National Electricity Transmission System Security and Quality of Supply Standards) operational criteria and the frequency containment policy. This ensures that the transmission system is planned on the basis of accepting a normal (i.e. relatively frequent) loss of power infeed of up to 1000MW, and an infrequent (i.e. in the region of up to four occurrences per year) loss of power infeed of up to 1320MW. The level of Response services contracted for by the System Operator is based on these levels of loss of power infeed.

At present there are several new developments being considered to meet the requirement for new generation in Great Britain, including coal and nuclear units in excess of 1000MW. Should these projects progress, under the existing arrangements their connections would be treated as customer design variations and hence to ensure that the quality of supply to other Users is not reduced, they would have the cost of holding additional Response targeted at them. The recommendation of NETS SQSS Amendment Report GSR007 issued in September 2009 was that the normal and infrequent loss limits in the NETS SQSS be raised to 1320MW and 1800MW respectively, from such time as a single generating unit greater than 1320MW connects to the system.

In order to maintain the quality of frequency on the GB system, National Grid spends around £170M per year on frequency Response services to cover sudden power infeed loss. All generating plant must be able to provide a minimum of 10% of their capacity as a frequency Response (in accordance with Grid Code requirements). National Grid has a regulatory incentive to minimise the cost of Response through BSIS (Balancing Services Incentive Scheme), and selects plant on a daily basis to provide Response services based mainly on their market price. The cost of Response is currently recovered through BSUoS uniformly from all classes of demand and generation on a MWh basis.

It was identified by the SQSS Review Group that if a number of these large new generation units connect to the system, the estimated cost of Primary and Secondary Response could increase. Primary frequency response is required to contain the system frequency within limits in the ten second period immediately following an instantaneous loss on the system, whilst secondary frequency response is required to recover such a loss once it has been contained. A cost/benefit analysis was undertaken by the review group which calculated the increase in Response required to cover the risk imposed by six additional 1800MW power stations on the system. This analysis estimated that the annual cost of Response could increase from £160M to £319M. Given this potential increase in costs, National Grid believes that it is appropriate to review the charging methodology for Response services.

[3] ESQCR at www.statutelaw.gov.uk

4 Summary of Responses to the Pre-Consultation

4.1 Industry Representations

Eleven responses were received to the GB-ECM19 pre-consultation document, of which all but two considered that continued socialisation of all response costs was appropriate. General comments received in the responses are summarised in Table 1 below.

Table 1

Respondent	General Comments
British Wind Energy Association	Charging on the basis of size is discriminatory and creates investment uncertainty.
Centrica	Charging on the basis of size is discriminatory, creates investment uncertainty, is not cost-reflective and is a disincentive for large generators. Frequency response is a shared benefit and the SQSS limits have previously been increased without reviewing the charging arrangements.
Dong Wind (UK)	Charging on the basis of size creates investment uncertainty, is a disincentive for large generators and the SQSS limits have previously been increased without reviewing the charging arrangements.
Drax Power	Charging on the basis of size creates investment uncertainty, is not cost-reflective and is a disincentive for large generators. Frequency response is a shared benefit and targeting will not reduce costs. If a targeted approach is progressed, it is not appropriate to use TEC to target costs, instead generators who deviate from physical nomination should be penalised. Ex-ante charges based on metered volume are preferred. There is no need for different charging for transmission spurs.
EdF	Charging on the basis of size is discriminatory, creates investment uncertainty, is not cost-reflective and is a disincentive for large generators. Frequency response is a shared benefit and the costs cannot be forecast with sufficient accuracy. Banding would be arbitrary. Targeting opposes other National Grid licence objectives. There is no need for different charging for transmission spurs.
E.ON	Charging on the basis of size is discriminatory, is not cost-reflective and is a disincentive for large generators. Frequency response is a shared benefit, the costs cannot be forecast with sufficient accuracy and targeting will not reduce costs. If a targeted approach is progressed, it is not appropriate to use TEC to target costs, however charges based on metered volume would be preferred. There is no need for different charging for transmission spurs.
International Power	Charging on the basis of size is not cost-reflective. Frequency response is a shared benefit. If a targeted approach is progressed, it is not appropriate to use TEC to target costs.

Respondent	General Comments
Moyle Interconnector	Charging on the basis of size is a disincentive for large generators. If a targeted approach is progressed, it is not appropriate to use TEC to target costs. There is no need for different charging for transmission spurs.
RWE	There may be a case for targeting costs based on TEC, however wider system benefits of response should be considered. There is no need for different charging for transmission spurs.
Scottish Power	Charging on the basis of size creates investment uncertainty and is a disincentive for large generators. Frequency response is a shared benefit, the costs cannot be forecast with sufficient accuracy and targeting will not reduce costs. Banding would be arbitrary. If a targeted approach is progressed, charges based on metered volume would be preferred. There is no need for different charging for transmission spurs.
Westinghouse	Charging on the basis of size more accurately reflects costs to Users. Continued socialisation will distort the nuclear reactor supply market, and hence is anti-competitive.

The full responses to the pre-consultation are available on National Grid's charging website: http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/

5 Analysis

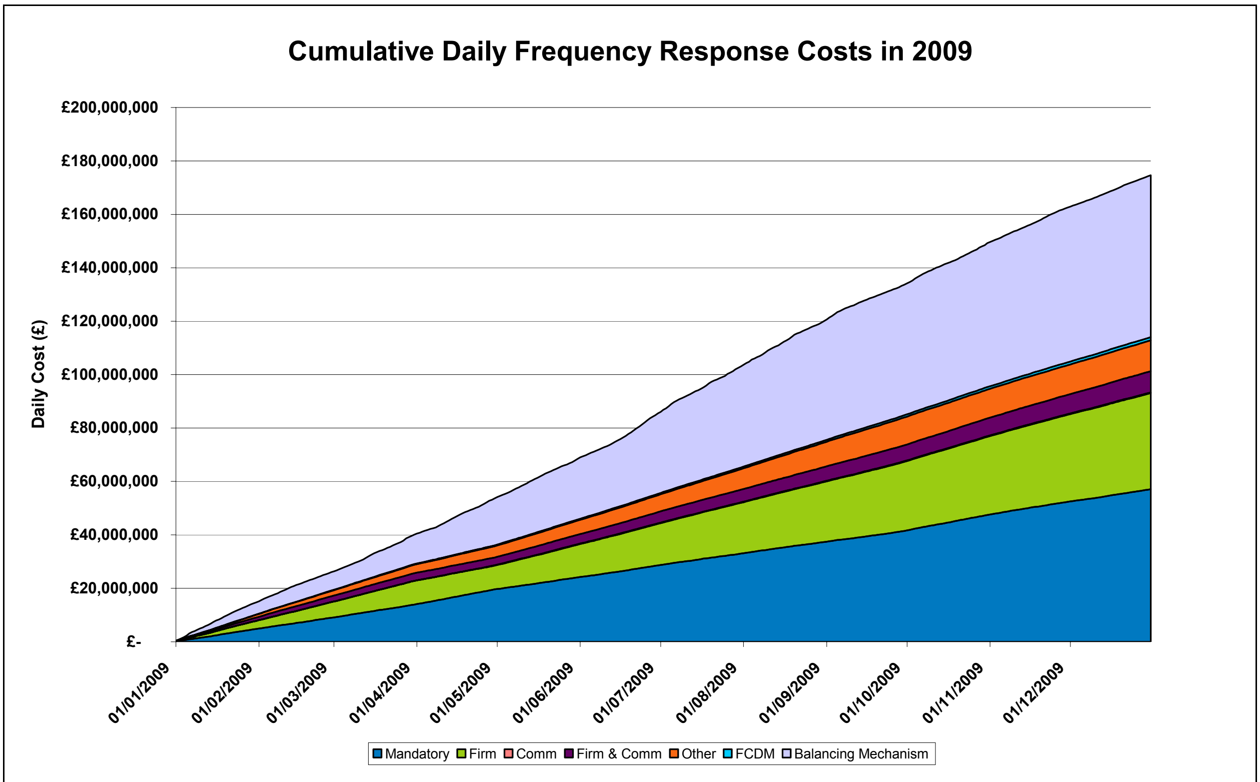
The cost benefit analysis contained within GSR007 identified a significant additional cost as a direct result of increasing the loss limits. This has been further investigated to determine what an appropriate level of cost recovery from an 1800MW risk would be, and hence whether changing the methodology for response charging would better facilitate the relevant objectives. This analysis used the cost/benefit analysis contained within GSR007 as a starting point, however the aim of the work is to identify the impacts of GSR007 on the charging arrangements and not to revisit the conclusions of the SQSS review group. The analysis therefore assumes that GSR007 is approved by Ofgem, allowing generation units up to 1800MW to connect to the system with their attendant risks and rewards, and attempts to identify how the charging arrangements should change to reflect this new state of affairs.

The costs and benefits identified in the GSR007 analysis that are directly related to the construction and operation of the transmission system have been investigated further, and several options for their apportionment have been outlined. National Grid welcomes respondents' views on the analysis presented and the appropriateness of the assumptions detailed in this section.

5.1 Cost of Additional Response

The average historical cost of response identified in GSR007 was £159M, which was based on an average response requirement of 800MW and made up of £105M for primary response, £45M for upward reserve and £10M for downward reserve. The data for the 2009 calendar year, as shown in Figure 1, sums to £174.6M.

Figure 1



To identify the average volume of response associated with this cost, a constant instantaneous loss risk of 1320MW was assumed, and the primary response requirement calculated for differing demand levels (Table 2) using the simplified equation below.

$$\text{Required Response} = D \times S \times F + \text{LossRisk}$$

Where:

D = system demand (MW)

S = frequency sensitivity of the load (Hz^{-1})

F = allowed frequency deviation (Hz)

LossRisk = size of individual generator (MW)

This formula ignores the dynamics of providing response, i.e. it assumes that response is available in time to ensure that the frequency limits are maintained and that the frequency returns to above 49.5Hz within 60 seconds.

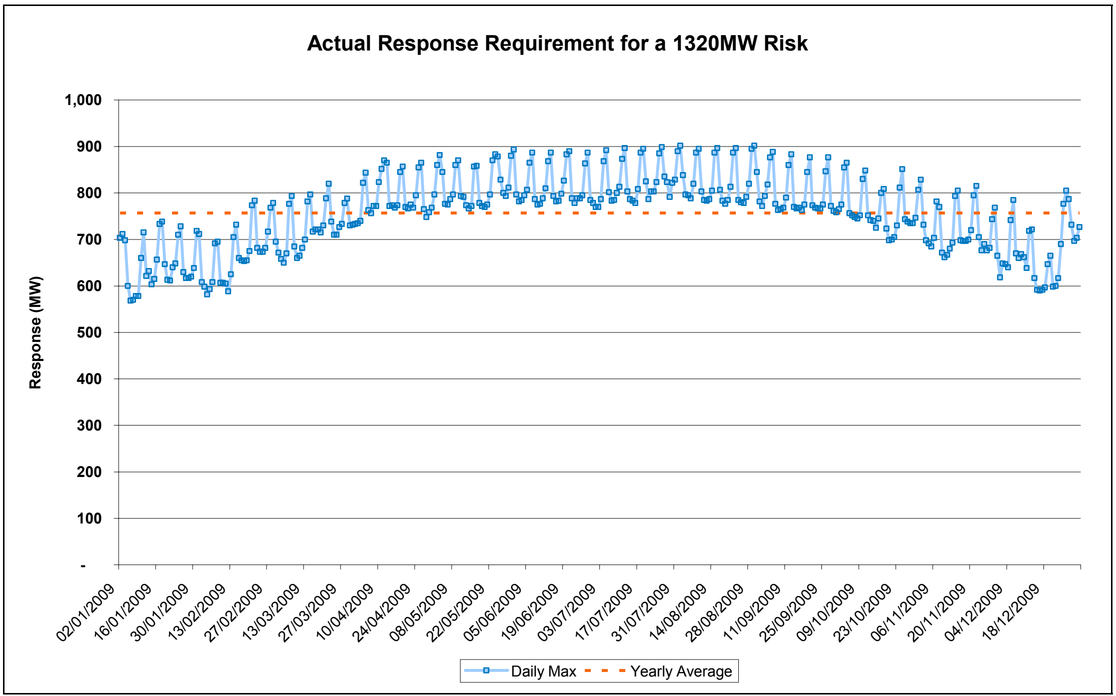
Whilst the frequency sensitivity of a load will vary, for the purposes of calculating response charges it is assumed that a change in frequency of 1Hz will change the generation/demand split by 49/50, i.e. 2% or a value of $0.02Hz^{-1}$. For plant creating loss risks below the normal loss limit, the allowable frequency deviation is -0.5Hz, whereas for plant above the normal loss limit the allowable frequency deviation is -0.8Hz.

Table 2 – Response Required for Instantaneous Loss of 1320MW

GB Demand (MW)	15000	20000	25000	30000	35000	40000	45000	50000	55000	60000	65000	70000
Required Response (MW)	1080	1000	920	840	760	680	600	520	440	360	280	200

This required response can then be cross-referenced against the daily demand seen on the transmission system in 2009 (Figure 2).

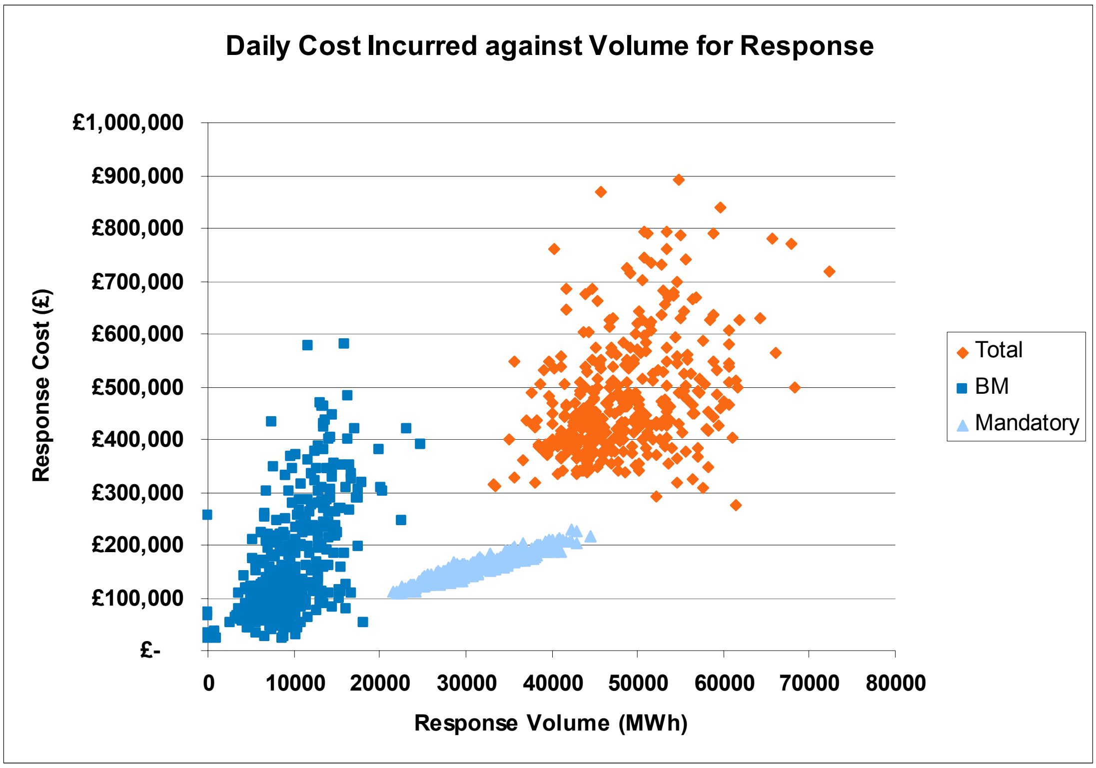
Figure 2 – Response Requirement for a 1320MW Risk in 2009



Taking an average across the year results in a volume of 757MW for a 1320MW risk in 2009. Increasing the infrequent infeed loss limit from 1320MW to 1800MW would require an additional 480MW[4] of response to be held, i.e. for an 1800MW risk the system would require a total of 757MW + 480MW = 1237MW of response to be held. Assuming that the additional risk arises from a baseload nuclear station, a reasonable approximation is that the response holding will be required every day. Using the historical 2009 data, a unit cost of response of £174.6M / 757 = £0.23/MW per year can be determined, and therefore the annual cost of holding an additional 480MW of response is estimated to be **£110.7M**.

This additional cost assumes a linear relationship between cost of response and response requirement. Considering the 2009 response data, it is possible to correlate daily response volumes against their cost to identify the underlying relationship (Figure 3).

Figure 3 – Cost of Response against Volume of Response in 2009



The graph clearly shows that there is a linear relationship between the cost of holding Mandatory Frequency Response, which is to be expected as the cost is regulated under CUSC section 4.1.3.8, however the cost of holding and utilising response through the Balancing Mechanism has less of a correlation due to its dependence on the market price on the day. On balance, National Grid believes that it is appropriate to assume a linear relationship between cost and requirement.

5.2 Cost of Reserve

Operating reserve is defined as the source of extra power required by National Grid to meet unforeseen demand and/or generation changes. This ensures that there will be headroom on generators that are instructed to hold response. Whilst it is does not vary with system demand, the introduction of larger loads onto the system will have a

[4] Annex 6: http://www.nationalgrid.com/NR/rdonlyres/EEEB8EDB-6AA5-4D44-BFDC-763ECE251E73/31739/SQSS1320Reportfinalv10_040209_.pdf

direct impact upon the level of risk that reserve levels must cover, as it may be called for more often.

5.2.1 Downward Reserve

During periods of low demand, such as overnight, National Grid must ensure that there are sufficient additional units capable of reducing generation within the half-hour period in order to balance sudden losses of demand or increases in generation. Nuclear generation is unsuited to shutting down over trough periods, and hence the introduction of significant levels of nuclear into the generation mix may increase the costs of downward reserve.

Whilst the cost / benefit analysis in GSR007 included a nominal cost of £10M for downward reserve, this is not included in this consultation as it arises from the assumed increase in inflexible nuclear capacity rather than as a result of the increase in generator size. As the charging arrangements do not discriminate based on fuel type, it is not appropriate for this cost to be factored in.

5.2.2 Upward Reserve

The analysis in GSR007 determined that potential large new loads would not significantly affect the requirement for regulating reserve, due to their reliability and size, but would have an impact on the requirement for frequency reserve. Frequency reserve ensures that there is sufficient headroom on the gensets that generators are instructed to hold for response.

On average, each unit of frequency reserve can hold 0.55MW of response, and therefore an increase in response holding of 480MW will require an increase of 872.7MW of frequency reserve. In 2009, reserve costs totalled £97.7M for Balancing Mechanism costs and £87.4M for Ancillary Services costs to cover an estimated requirement of 3500MW from GSR007. This gives a unit cost for reserve of (£97.7M + £87.4M) / 3500MW = £52.89/kW. Therefore an additional annual cost of **£46.2M** is predicted.

5.3 Benefit of Reduction in Circuits

The potential for the loss of a generation circuit greater than 1000MW would currently require that an additional circuit is constructed[5], and therefore increasing the infrequent loss limit and normal loss limits will decrease the amount of circuits needed to meet the SQSS. This reduction in TO's capital expenditure can be estimated and included within the analysis.

Without knowing the specific system reinforcements required for each generator, it is impossible to know exactly what the saving in infrastructure would be. The analysis in GSR007 assumed that a 150km circuit could be saved, based on the Dounreay to Beauly route in the North of Scotland. It is unlikely that every large generator will require such a significant length of circuit, however an average circuit saving of 10km per generator does not seem unreasonable.

The 2009 Seven Year Statement includes four generators of between 1000MW and 1320MW that would currently require a double circuit to meet the SQSS requirements on loss of power infeed. Raising the normal infeed loss limit to 1320MW would mean that four circuits rather than eight would be sufficient. Additionally, seven generators of greater than 1320MW are planned by 2020, and these would only need two circuits rather than three. This would save a total of eleven circuits.

[5] Section 2: http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/DocLibrary/

With an average circuit saving of 10km, eleven circuits would save 165km. Identifying a single unit cost for 400kV OHL for all three TOs is difficult without having access to confidential information on historical project costs, however data in the recent ENSG report[6] on new double circuits from Wylfa to Pentir (£2M/km) and Bramford to Twinstead (£70M for a 35km line, i.e. £2M/km) results in an approximate unit cost of £1M/km for a single circuit. It is recognised that a single circuit is not half the cost of a double circuit, however this is a acceptable approximation for the purpose of this analysis. This results in a capital cost saving of £165M, which when annuitised over 50 years at 6.5% gives an annual benefit of **£11.2M**.

It may be that there is a larger saving in moving from three to two circuits than in moving from two to one circuit, due to the reduction in required OHL infrastructure such as wayleaves, towers, etc. National Grid invite views on what this saving may be, and whether it is material.

5.4 Benefit of Substation Design

Increasing the infrequent infeed loss limit to 1800MW will allow the design of future substations to use fewer circuit breakers than would otherwise be necessary. This is because three 500MW generators could be connected to a single busbar without requiring an additional circuit breaker to protect against a credible 1500MW loss for a busbar fault. This design change represents a saving in capital expenditure for the TO, and hence should be reflected in the cost / benefit analysis.

The 2009 Seven Year Statement forecasts around 20GW of new generation commissioning by 2020. GSR007 estimates that this level of investment would result in two instances where a circuit breaker would no longer be needed, plus three instances where a circuit breaker would not be replaced during a TO's normal asset replacement activities. The approximate cost of a 400kV circuit breaker is £1M, and therefore the annuitised cost of five of these over 50 years at 6.5% would be **£0.34M**.

5.5 Benefit of Larger Inter-Trip Volume

If more response is held, the maximum volume of generation armed on system to generator inter-trips could be increased above the current 1320MW limit, which would reduce operational costs. In order to quantify what this benefit may be, the Cheviot boundary has been used on the assumption that it would provide a similar volume of additional inter-trip.

The Cheviot boundary has a single circuit transmission limit at present of 1200MW, which would increase to the 1600MW limits of the remaining circuits as a result of the implementation of GSR007. Assuming that the proportion of constraint actions that also involve inter-trips at the boundary is 15%, and that the difference between the average cost of constraint actions in the Balancing Mechanism and intertrip actions is approximately £30/MWh, an annual benefit can be arrived at as follows:

$$400\text{MW} \times 8760\,\text{hours} \times 15\% \times £30/\text{MWh} = £15.8\text{M}$$

Therefore the estimated annual benefit as a result of increased inter-trip limits is **£15.8M**.

5.6 Summary of Costs and Benefits

Table 3 shows the total benefit that should be assumed when considering the appropriate methodology for charging for response.

6 http://www.ensg.gov.uk/assets/ensg_transmission_pwg_full_report_final_issue_1.pdf

Table 3 – Summary of Charging Impacts

Cost	£M
Response	110.7
Reserve	46.2
System Design	-27.3
Total	129.6

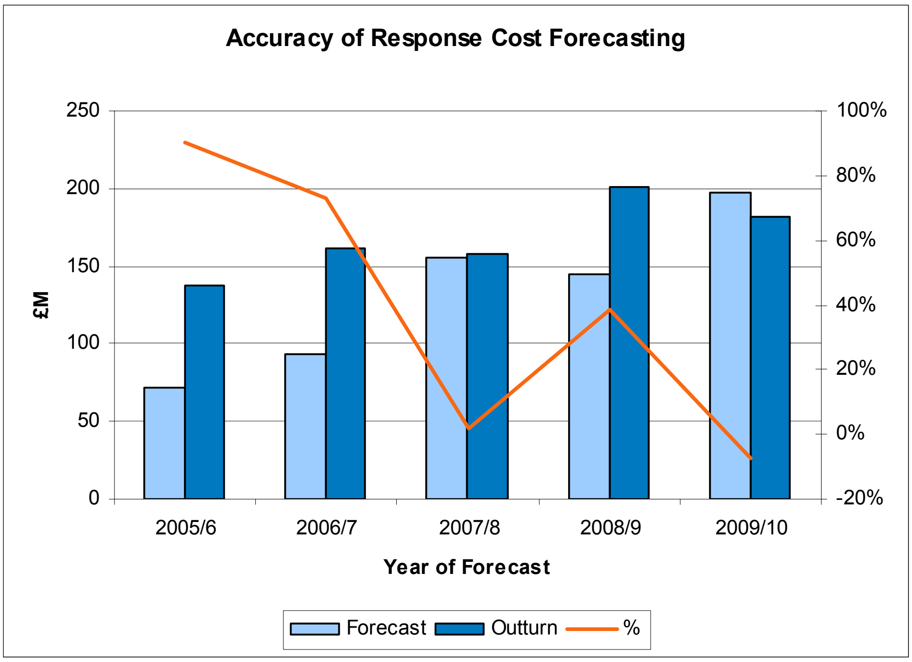
This indicates that an additional £129.6M per year will need to be recovered through response charging as a result of the implementation of GSR007. This means that for a single baseload 1800MW risk, the additional daily cost directly attributable to it would be £129.6M / 365 = £355k.

5.7 Ex-Ante or Ex-Post Charge Setting

The pre-consultation asked for views on the merits of moving to an ex-ante process for charging response, whereby costs are forecast and charges set for a fixed period, and continuing with an ex-post process, whereby the incurred costs are charged on a daily basis to Users. Whilst only one respondent directly gave a preference, the fact that the majority of respondents wanted to continue with the current arrangements is an indirect indication that there is no appetite for response charges to be set ex-ante.

To ascertain the potential accuracy of forecasting response costs at a high level, the annual forecast for the response portion of the Balancing Services Incentive Scheme (BSIS) was compared to the actual cost incurred by National Grid in that year (Figure 4).

Figure 4 – Annual Response Cost Forecasts Against Outturn



It can be seen from this that there is significant uncertainty associated with a yearly forecast. This uncertainty would be exacerbated when attempting to forecast over a number of years due to changes in generator numbers and strategies, and technical and code changes. This is ably demonstrated by comparing the forecast cost in 2005 with the outturn cost in 2009, which shows that the industry changes that occurred within that time (such as the introduction of BETTA, the growth of wind generation in Scotland and changes in commercial behaviour) resulted in costs that were over 150% higher than expected.

This may make such information of limited value when incorporating future response costs into investment decisions, particularly on longer life assets, and with this in mind National Grid have only considered an ex-post charge in this consultation. Views are invited on this assumption and also whether setting charges for just one or two years would be worthwhile to the industry.

5.8 Charging Options

Through responses to the pre-consultation and in discussions with the industry, National Grid has identified three potential solutions to future charging for response. These solutions are: to continue with a commodity charge, to move to a charge based on the capacity of the risk, or to use multiple commodity charges banded by generators' TEC.

In all the options discussed below, it is assumed that demand continues to incur 50% of the total response costs. This is because it is demand Users that require uninterrupted quality of supply, and National Grid maintains a minimum response requirement of 350MW to cover dynamic frequency changes which would affect this. It is not considered necessary at this time to consider targeting response costs at different sizes of demand due to the relatively small risk size of the majority of demand sites, however this assumption will be kept under review.

The minimum response requirement of 350MW also means that generators below this size effectively pose no additional loss risk to the system, and this should be considered when assessing any methodology changes.

The new approaches outlined below assume that Users are only charged for their own risk, and any additional risk caused by the connection of multiple smaller generators to a single transmission spur, for example, would not be included. This holds for offshore spurs as well as onshore. As transmission spurs have historically had a much lower rate of instantaneous trip frequency than either large generators or interconnectors (0.01 to 0.1 trips per year compared with 0.5 to 2 trips per year, depending upon the length of spur), National Grid believes this to be appropriate, however views are specifically invited on whether generators on such spurs should share the costs of this larger risk.

Views are welcomed on the appropriateness of all assumptions used in determination of the options and on what timescales those assumptions should be reviewed.

5.8.1 Commodity Charge

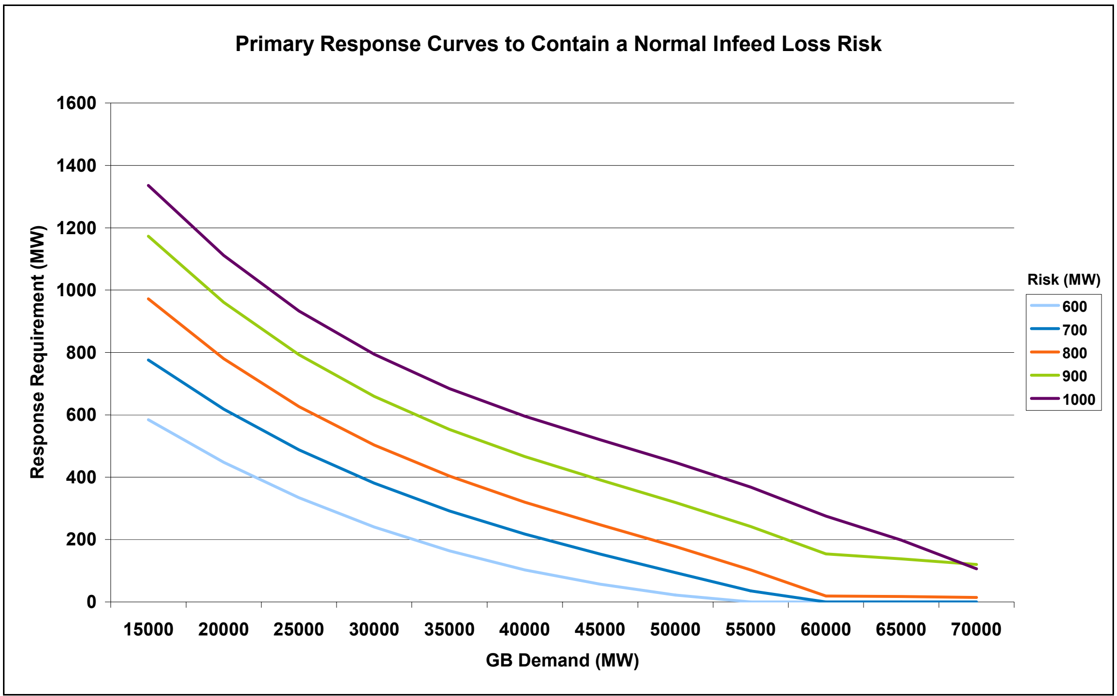
In this option, which represents the status quo, response costs incurred by National Grid are apportioned equally to all Users based on their usage of the system on the day. This approach effectively socialises all response costs across the industry, regardless of the actual risk that each User imposes on the system. The consequence of this option would be that a small generator operating at baseload would pick up a proportion of the response costs larger than the risk it is causing, whilst a large generator operating intermittently would pick up the same proportion of the costs despite representing a sizeable risk to the system and imposing substantially more cost.

5.8.2 Capacity Charge

In this option, response costs are apportioned to each User depending upon the size of the risk that they impose on the system rather than their use of the system. This approach could calculate each Users' charge based on either the highest risk that they would theoretically cause within the day or the average risk across the day. This would require National Grid identifying the individual risk capacities within each half-hourly balancing period.

In identifying the level of response required for a certain size of risk, National Grid uses response curves such as those shown in Figure 5.

Figure 5 – Example Response Curves



These curves depend on the size of the risk and the demand in each balancing period, and can be approximated using the simplified formula detailed in section 5.1.

At higher demand levels this formula can result in a negative requirement, because each individual risk represents a smaller proportion of the overall system demand and therefore will have less of an impact on frequency due to system inertia. As a result of this, charges would need be collared at zero to better reflect reality. Depending upon the demand, this could result in smaller generators up to a certain size not being liable to pay any response charges. As such generators impose far lower risks upon the system (as shown in Figure 5), this is a good representation of the physical situation.

The simplified formula in section 5.1 is for a single generator, and assumes that each generator is the only one imposing a risk on the system. To create an individual charge requires that a £/MW unit cost is identified from the total cost of response and the sum of all the theoretical response requirements.

A User's daily charge will therefore be given by the following formula, which assumes that demand continues to pick up half of the response costs:

$$\text{Charge}_i = 0.5 \times \frac{\text{Cost of Response}}{\sum_i [\max((D \times S \times F_i + \text{LossRisk}_i),0)]} \times \max((D \times S \times F_i + \text{LossRisk}_i),0)$$

Whilst the commodity charge option will automatically recover the necessary response costs, the cost recovery of a capacity approach will depend on the size of units that are operating and the demand level. To avoid under- or over-recovery of costs, the charges to Users would need to be adjusted, and therefore an recovery term is required in the formula for calculating Users' charges.

The charge for a generator i with its individual LossRisk_i and corresponding allowed frequency deviation F_i is calculated according to the following formula:

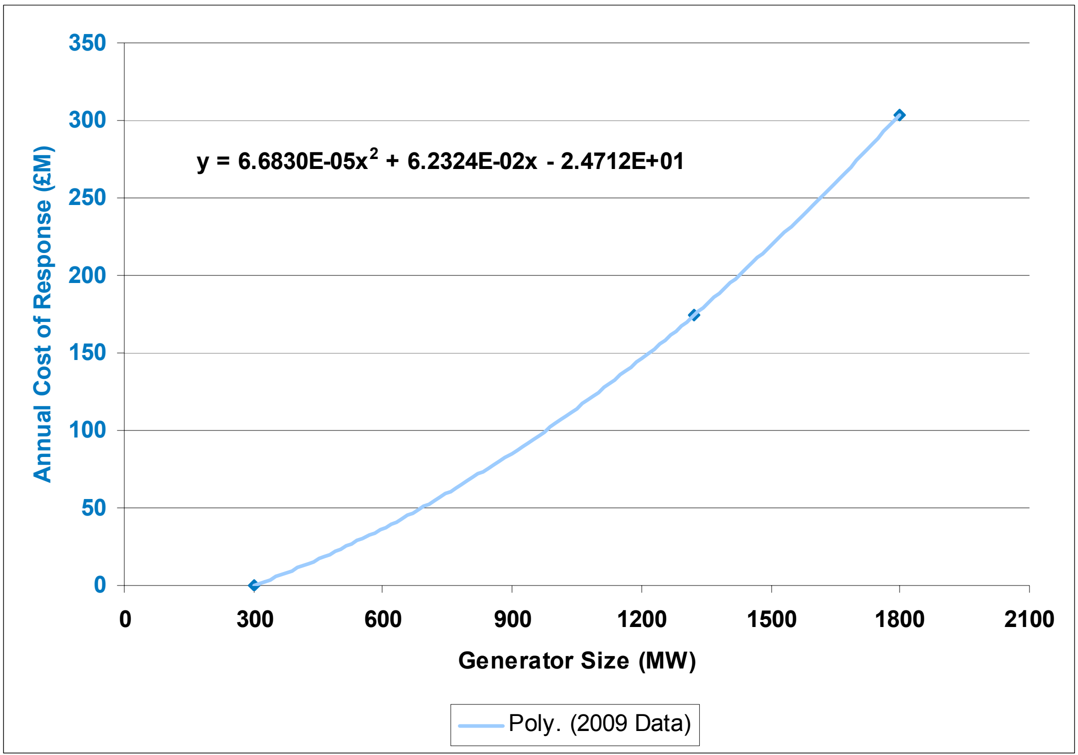
$$\text{Charge}_i = 0.5 \times \frac{\text{Cost of Response}}{\sum_i [\max((D \times S \times F_i + \text{LossRisk}_i),0)]} \times \max((D \times S \times F_i + \text{LossRisk}_i),0) + \text{RecoveryTerm}$$

5.8.3 Banded Commodity Charge

In this option, response costs are apportioned to Users based on their usage of the system on the day, but with different charges depending upon the size of the User. This approach is based on the existing commodity charge methodology, but split such that Users with similar levels of TEC are grouped in set bands which are charged different proportions of the cost incurred.

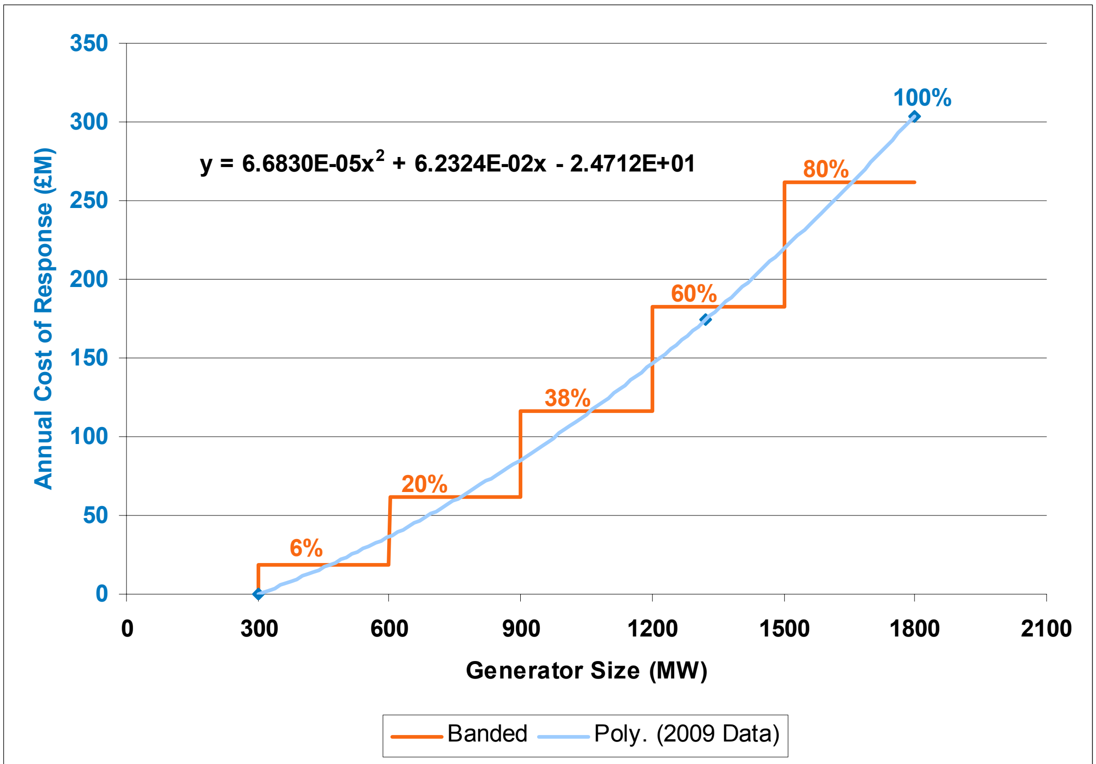
Splitting the charges between bands requires assessing what proportion of the incurred response costs should be attributed to each band. Using the actual cost and the estimated increase from the 2009 data, along with the risk levels that such costs cover, a mathematical relationship can be derived relating cost to response (Figure 6). This includes the assumption that for small risks there are no response costs, as described in section 5.8. This can then be used to identify what proportion of cost can be attributed to each risk level.

Figure 6 – Relationship Between Cost of Response and Risk Size



Banding ranges of 300MW have been used, as National Grid believes that this level of granularity provides a sufficient signal to reflect costs whilst minimising the number of charging bands. These bands were calculated using the relationship derived in Figure 6 and adjusted to ensure the mid-point was on the line (Figure 7). A percentage of the total estimated annual cost was then identified for each band, which can then be used to apportion the daily response costs between the bands.

Figure 7 – Derivation of Banding Levels



On a daily basis, the total response cost incurred is divided by the total throughput to get a £/MWh commodity charge, as is done at present. This charge will continue to be used for demand Users, whilst for generation it would be multiplied by the banding percentages and a recovery term added to ensure the correct level of cost recovery, as shown in the formula below.

$$\text{Charge}_i = 0.5 \times \frac{\text{Cost of Response}}{\text{Daily Throughput}} \times \text{Banding Term}_i + \text{Recovery Term}$$

Where the Banding Term would be as shown in Table 4.

Table 4 – Banding Term

Range (MW)	0-300	300-600	600-900	900-1200	1200-1500	1500-1800
Banding Term	0	1.06	1.20	1.38	1.60	1.80

5.9 Comparison Analysis

In order to determine the effect of each option on current and future Users, analysis was undertaken on a theoretical demand day with a flat profile of 38GW. To estimate the number and size of generators that would be running to meet that demand level, the total number of operational units and their capacities was taken from the Seven Year Statement. This total capacity was scaled down to meet 38GW, and the number of units of each size required was identified (Table 5). For the purposes of this analysis, it was also assumed that one 1800MW unit and one 1500MW unit would be operating.

Table 5 – Example Generation Split

Unit Capacity (MW)	Total No. of Units on System	Number of Gens Required
1800	*1*	*1*
1500	*1*	*1*
700	4	2
650	15	6
600	9	3
550	17	6
500	32	12
450	11	4
400	8	3
350	9	3
300	37	14
250	26	10
200	22	8
150	33	12
100	30	11
50	148	56

Using this estimate of operating generators (rounded to the nearest integer) and calculating the cost recovered from them, the impact of the differing approaches can be assessed (Figures 8, 9 & 10).

In order to determine the cost-reflectivity of each approach, a target cost for a notional 1800MW unit is required for comparative purposes. The additional daily cost of £355k for a baseload 1800MW unit can be used as a basis for the target.

Figure 8 – Cumulative Cost Recovery from Commodity Approach

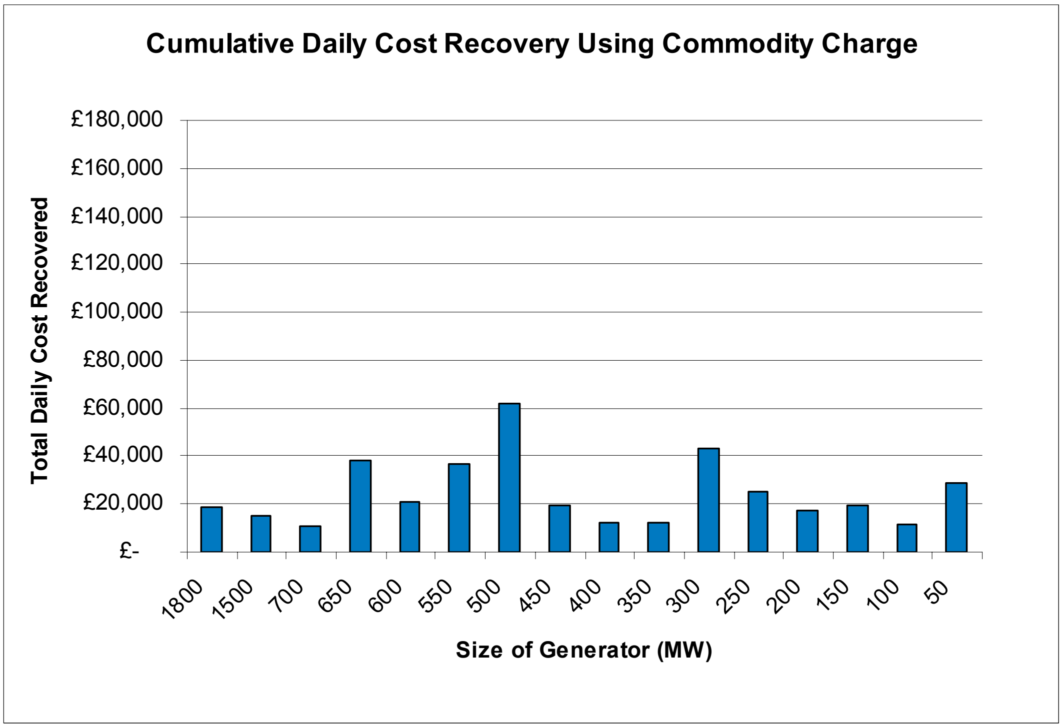


Figure 9 – Cumulative Cost Recovery from Capacity Approach

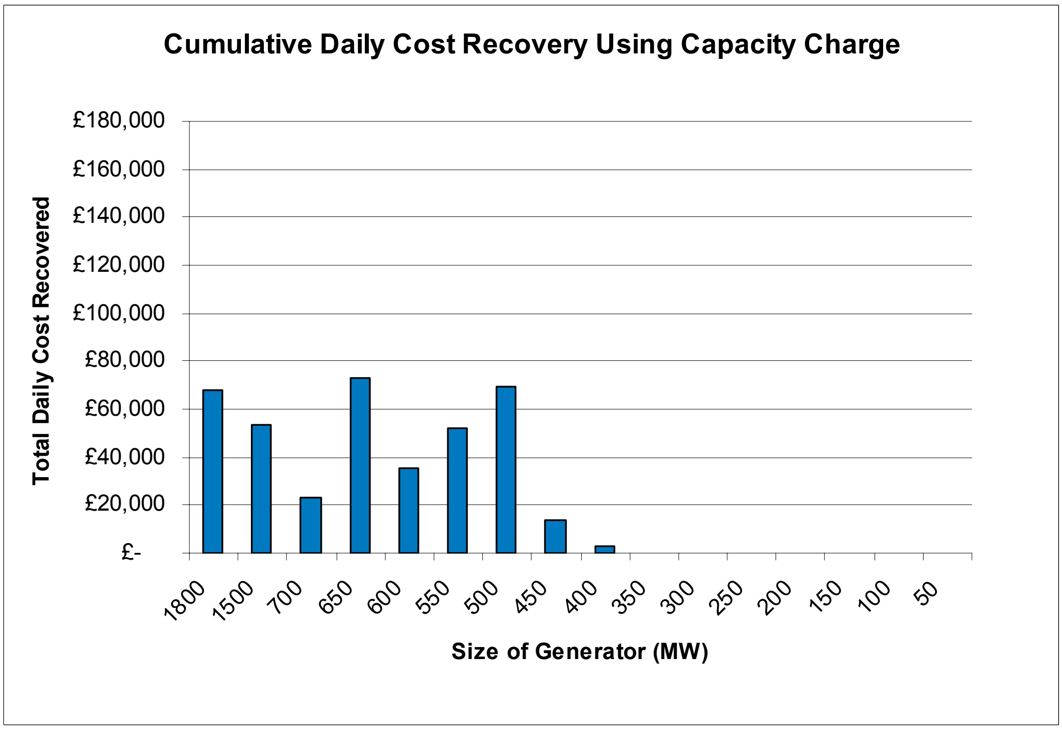
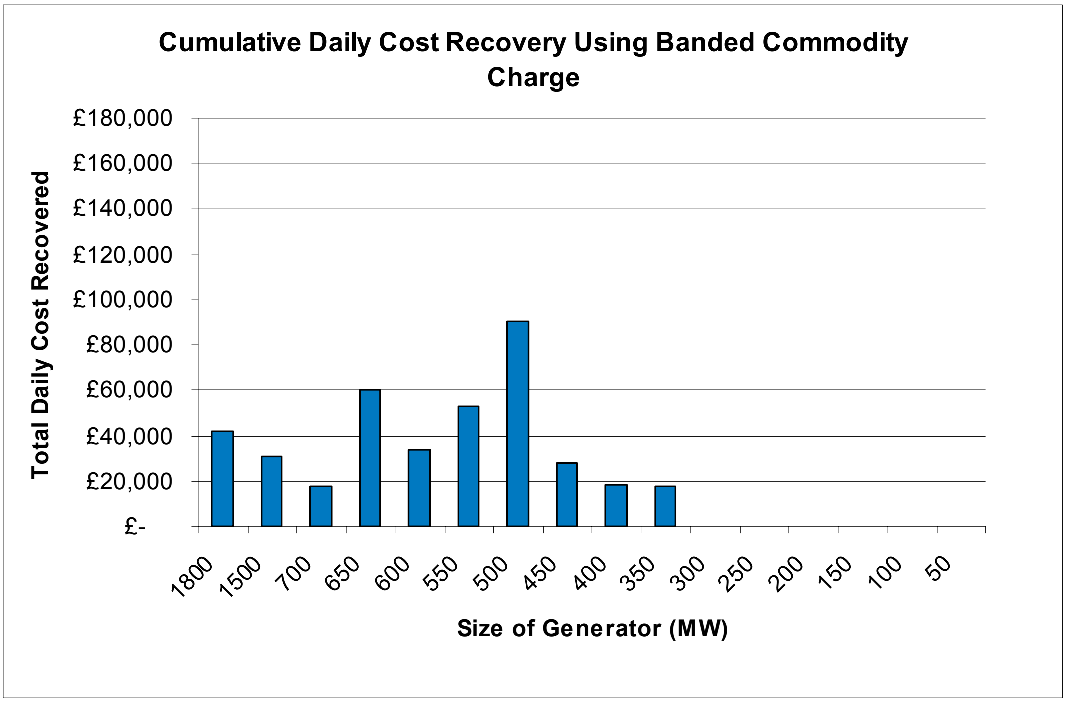
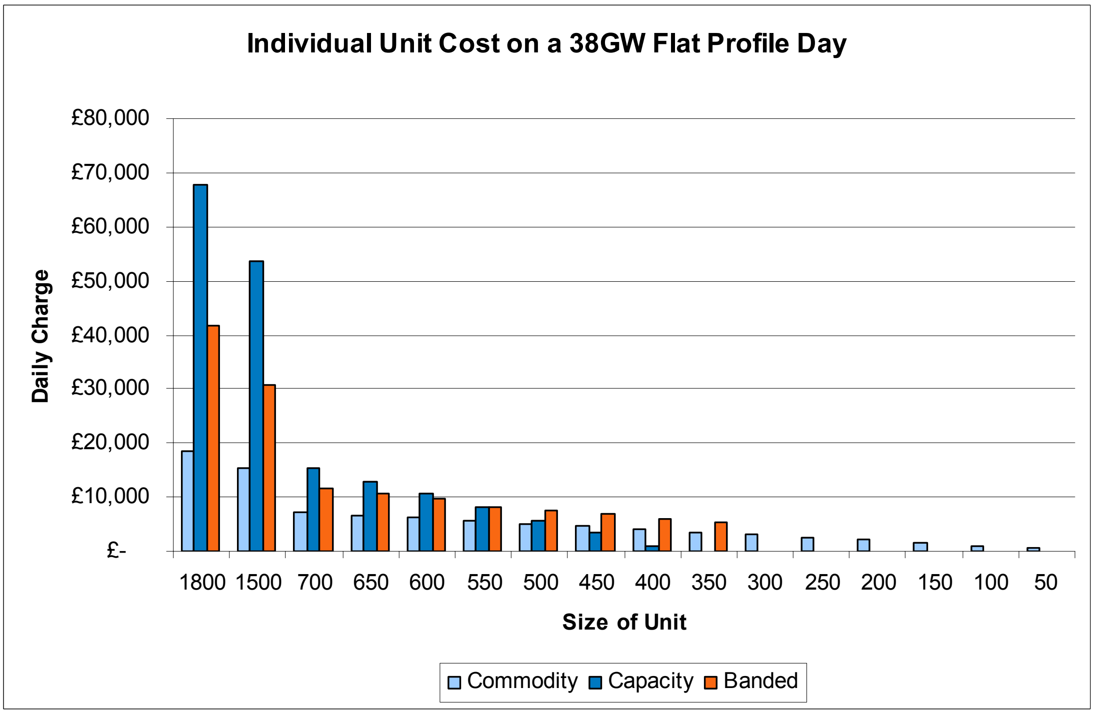


Figure 10 – Cumulative Cost Recovery from Banded Commodity Approach



To assess the impact on individual Users, the recovered costs are divided by the number of each size of unit, as shown in Figure 11. This assumes that each unit is operating as baseload.

Figure 11 – Example Costs for Individual Units



6 National Grid's Initial View

In setting and reviewing Use of System charges, National Grid has a number of further objectives contained in the Statement of Use of System Charging Methodology. These are to:

- offer clarity of principles and transparency in the methodology;
- inform existing Users and potential new entrants with accurate and stable cost messages;
- promote the optimal use of, and investment in, the transmission system by charging on the basis of services provided and incremental rather than average costs; and
- be able to be implemented within practical cost and time-scales.

National Grid has put forward two approaches to developing the methodology for response charging, along with maintaining the status quo. These approaches have been assessed to identify whether any better facilitate the relevant objectives. National Grid notes that the cost and timescales for implementing either of the two developments has not been considered as part of this consultation, although this will be included in the final report to the Authority along with any User implications should a change be proposed. Should the methodology for charging response be changed, there would be consequential changes required to the CUSC.

6.1 Assessment Against the Relevant Objectives

6.1.1 Commodity Charge

Facilitating Competition

A £/MWh commodity charge provides a transparent process for attributing costs, as all Users are paying a flat charge based on their use of the system. Whilst the daily costs incurred by National Grid in covering response can vary significantly (between £277k and £893k in 2009), a commodity charge ensures that Users know that they will always receive the same proportion of the costs, assuming similar running levels. Whilst this predictability in the relative charges between Users is a benefit to competition, this approach does not help Users in predicting the charges themselves.

Cost-Reflectivity

Ensuring that Users are exposed to the costs that they impose upon the system allows those costs to be factored into investment decisions, and therefore ensures that no participants are unduly disadvantaged. In a commodity charge, the costs incurred by National Grid in holding and using response are smeared back to all Users regardless of their impact on the system. This means that whilst large units are driving the requirement for response, smaller units are paying a disproportional amount of the costs, and the introduction of larger risks onto the system will only exacerbate this situation. There are therefore two aspects of the existing methodology that lack cost-reflectivity; firstly that larger units are paying for a level of risk that is less than the risk than they are causing, and secondly that smaller units are paying for covering a level of risk that they are not causing.

Developments in the Transmission Business

As more larger and smaller generators are commissioned, such as 1800MW nuclear sites and 50MW wind farms, the cost inequalities between smaller and larger generators will grow. Continuing with the existing commodity charging regime does not take this development into account.

6.1.2 Capacity Charge

Facilitating Competition

Basing response charges on a capacity approach provides a transparent methodology for apportioning costs between Users, as each User will have their charges calculated by the same formula. In order for an individual User to assess their daily charges, however, they would need estimates of the sum of the daily response requirements, as well as the daily demand and total response cost. Whilst it would be difficult for individual Users to know the sizes of all the other risks on the system on a day, it would be possible for National Grid to provide additional within-day data streams which could mitigate this uncertainty.

Cost-Reflectivity

The capacity approach is based on a marginal cost process that directly links a User's risk to their charge, and therefore large Users would pay for the cost of covering their risk. This direct linking to the daily response requirement would also ensure that when National Grid does not need to cover a User's risk, that User does not pay for response. The capacity approach therefore improves the cost-reflectivity for both larger and smaller risks.

Developments in the Transmission Business

Providing a direct link between the risk that a User imposes and the charge that they pay ensures that the arrangements for charging are scalable to future increases in generation risk beyond 1800MW, and hence this approach actively deals with this objective.

6.1.3 Banded Commodity Charge

Facilitating Competition

A banded £/MWh commodity charge provides a transparent process for attributing costs, as all Users of a similar size are paying a flat charge based on their use of the system. Users will know that they will always receive the same proportion of the costs relative to both risks of similar size and risks in other bandings, assuming similar running levels. Whilst this predictability in the relative charges between Users is a benefit to competition, this approach does not provide better predictions of the charges themselves. Additionally, the determination of the ranges of each band as well as the banding term would be subject to review and change in the future, and therefore the long-term stability of Users' charges could be affected.

Cost-Reflectivity

Splitting the existing commodity charge into bands, each incurring a separate proportion of the overall response cost, ensures that there is some consideration of the costs that different risks impose on the system, albeit indirectly. This is facilitated by the assertion that risks of 300MW and below should not pick up any charge for response, which more accurately reflects the physical situation. Within each band, however, generators of different sizes will pay the same £/MWh charge despite imposing different risks and hence different costs, which limits the level of cost-reflectivity that is obtainable without introducing significant complexity.

Developments in the Transmission Business

In targeted proportionally more of the cost to larger Users and less to smaller Users, the banded approach attempts to reflect the development of the system into one with a wider spread of generation risks. However, the inclusion of specific bands within which Users all pay the same charge limits the scalability of the approach, and hence it is likely that the methodology would have to be reviewed at a future date.

6.1.4 Summary of Assessments

The above assessments have been summarised in Table 6.

Table 6 – Summary of Assessments

	Facilitates Competition			Cost Reflectivity			
Option / User	Transparency	Predictability	Stability	Services provided	Incremental	Practical cost	**Developments in the transmission business**
Commodity Charge	✓	✓	✓	×	×	✓	×
Capacity Charge	✓	✓	✓	✓	✓	-	✓
Banded Commodity Charge	✓	✓	×	✓	×	-	✓

Based on the above assessment of the three approaches against the relevant objectives, it is National Grid's initial view that the current methodology of recovering response costs based on a flat commodity charge is insufficiently cost-reflective. Of the two proposed developments, it is National Grid's initial view that, on balance, the capacity approach better facilitates the relevant objectives.

6.2 Implementation

National Grid envisages that the earliest implementation date for any proposed change to the methodology for response charging would be 1st April 2012. There will be changes required to information systems, data processing and audit, BSUoS systems, etc. along with associated CUSC changes which have not been considered as part of this consultation, and the associated costs will need to be identified and agreed with the authority. National Grid seeks information from Users as to the potential cost and timing implications on Users' systems to ensure a robust cost benefit analysis can be presented.

7 Responses to the Consultation

Comments and views are invited on all of the issues raised in this consultation document. To ensure that your comments and views are considered as part of National Grid's forthcoming consultation conclusions report, responses must be received by close of business on 09 July 2010. All responses will be published on National Grid's charging website unless clearly marked confidential.

If you wish to provide comments on this consultation document, responses are preferred via email to: adam.sims@uk.ngrid.com.

Alternatively, parties can send their comments in writing, addressed to:

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If you have further queries, please contact Adam Sims on 01926 655292 or Patrick Hynes on 01926 656319.