



Report on GB charging condition 3

**The treatment of intermittent generation in the GB
Charging Methodology**

August 2006

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Executive summary

In accepting the GB charging methodology the Authority placed a number of conditions on National Grid Electricity Transmission plc (National Grid). Condition 3 covers the treatment of intermittent generation within the use of system charging methodology.

Initially National Grid discussed condition 3 at the Transmission Charging Methodology Forum (TCMF), where a process for taking forward the review was agreed. National Grid then consulted with the industry through a questionnaire to gather views on the treatment of intermittent generation and possible alternatives. National Grid also discussed the issues at the Charging Issues Standing Group (CISG), where attendees have an opportunity to discuss issues in detail.

National Grid has considered the industry responses to the questionnaire and carried out a review of the processes that lead to transmission investment. Particularly, those stemming from the GB Security and Quality Supply Standard (GB SQSS), along with the interaction between the GB SQSS; the access rights provided under the Connection and Use of System Code (CUSC) and the basis of charging for use of system.

The responses were reasonably evenly split on whether the methodology should be changed or not, with many of the issues raised relating to much wider charging and access arrangements. Many of the responses also appeared to be founded on an understanding that the planning process was based solely on a deterministic assessment.

The GB SQSS includes both economic and deterministic assessment processes. Economic assessment requires licensees to provide an economic level of infrastructure investment, subject to a minimum level derived from a deterministic assessment carried out at peak system demand. The principle objective of the economic assessment is to minimise the total costs experienced by all transmission licensees (including capital infrastructure and annual operational costs). As well as the peak demand scenario, economic assessment also considers system conditions that can be reasonably expected to occur throughout the course of a year. The economic consequences of not providing the requested level of access come from the financially firm nature of access rights.

The access rights provided under the CUSC are the same across all classes of generation. Taking account of the access rights, the level of investment provided through economic assessment for intermittent generation is not discernibly different to that provided for conventional generation. This is because the infrastructure investment level is driven by consequences of not providing access.

Having reviewed the GB SQSS and being mindful of National Grid's wider licence obligations, particularly discrimination, National Grid can find no

evidence that intermittent generation consistently causes less investment on the transmission system than conventional generation.

In conclusion National Grid does not intend to propose any modifications to the charging methodology in respect of condition 3. However, National Grid acknowledges that the whole issue of connecting intermittent generation is a developing area and National Grid itself has initiated a review of how individual types of generation are dealt with in the GB SQSS. In addition, the issue of access to the transmission system and the nature of the associated rights (and obligations) are also being discussed in a number of industry forums.

Should the review of the GB SQSS lead to a material change in investment planning process, or different access arrangements for intermittent generation be developed under the appropriate governance arrangements, National Grid would then be required through existing licence conditions to review the impact of such changes on the GB use of system charging methodology.

1. Introduction

In approving the GB Use of System Charging methodology the Authority placed a number of conditions on National Grid. This report covers condition 3:

'To review, invite views and to consult on alternative methods of treating intermittent generation (such as wind-farms) in the use of system charging methodology. If the review identifies potential improvements to the existing methodology, to bring forward proposals to modify the use of system methodology in this regard consistent with implementation in April 2007. In the event that National Grid concludes that there are no further improvements, National Grid should publish a report setting out the conclusions of the review.'

This report summarises the review National Grid has carried out including the discussions with the industry. This report also seeks to inform and clarify how and why investments are made under the economic assessment mechanism described in the GB SQSS¹. This report includes a high level summary of the transmission system planning process and application of the different elements of the GB SQSS.

For the purposes of this report National Grid has interpreted 'intermittent' generation as renewable plant that does not have full control over its primary fuel source to the extent that it cannot plan in the longer term to run at maximum output at times of system peak. As highlighted in the summary of responses, this is not necessarily a common view across the whole industry.

In carrying out the review National Grid has discussed the issues at the TCMF, and its sub group the CISG. National Grid consulted with the industry through a questionnaire. Through this National Grid sought views on a number of issues relating to intermittent generation. National Grid agreed it would report back to TCMF on the findings of the review and then progress this summary report, taking forward any amendments in parallel if required.

In summary, based on the current interpretation of the GB SQSS, National Grid believes equivalent investment is being made to connect intermittent generation as would be made for equivalent conventional generation. Through explaining the planning process this report seeks to demonstrate how designing the system in a coordinated, economical and efficient manner to facilitate the connection of intermittent generation, notably with the same rights under the CUSC as any other generator, equivalent levels of investment are made as for conventional generation. National Grid has reviewed a number of connection projects for intermittent generation and, on average, cannot find any quantifiable evidence that 'intermittent' generation leads to lower levels of infrastructure investment.

¹ Nothing in this report should be taken as altering the GB SQSS in anyway. In the event of a conflict the GB SQSS takes precedence. The GB SQSS is available on National Grid's industry information website.

The treatment of differing types of generation, in particular wind generation, is currently being reviewed in the GB SQSS and is also the subject of wider industry debate. Should the review of the GB SQSS lead to changes in the planning process that can be shown to lead to less investment, or after more experience of connecting and operating a system with intermittent generation shows consistently lower costs, then a further review would be required. If changes to the wider framework were implemented a review of charging arrangements would also be required. Such reviews would be consistent with National Grid's licence duty to ensure the charging methodology results in charges which reflect the costs incurred by the licensees and properly takes account of changes to the transmission business.

The following sections briefly describe the licence obligations and the wider context this report is prepared under. The report then goes on to describe the deterministic and economic assessments that form the basis of the investment process, in particular describing in detail some of the issues to be considered in an economic assessment. The appendices provide simple generic examples of these assessments. The report then goes on to discuss some of the issues raised by industry participants during the review. Finally, the report briefly summarises the main issues and presents National Grid's conclusion.

2. Licence obligations

As the transmission licensee 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 also required to have a charging methodology that achieves the following relevant objectives detailed in licence condition C5:

- a) To facilitate effective competition in generation and supply.
- b) To reflect, as far as reasonably practicable, the cost incurred by transmission licensees in their transmission businesses.
- c) In so far as is consistent with a) and b) above, and as far as reasonably practicable, they properly reflect developments in transmission licensees' transmission businesses.

In addition to the above relevant objectives, licence condition C7 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. Therefore in order to have specific charging arrangements for intermittent generation National Grid must be able to provide evidence to support this.

Licence condition C4 also provided the Authority with the option to make the approval of the original GB charging methodology conditional on further actions that would make the methodology better meet the relevant objectives. In respect of the use of system charging methodology the Authority placed five conditions on National Grid.

National Grid, along with the Transmission Owners (TOs), has a licence condition to comply with the GB SQSS, Condition C17 and D3 respectively. The GB SQSS provides for additional capacity above a deterministic minimum level where this can be economically justified. Since the transmission licensees have a duty under the Electricity Act to develop an efficient and economical transmission system, they are effectively obliged to invest to a higher standard than the deterministic criteria in circumstances where the additional capacity can be economically justified.

3. Development of the GB charging methodologies

During the development of the GB methodology the treatment of renewables was raised a number of times in response to consultations. Several respondents commented that the indicative tariffs would have an adverse affect on the environment and the government's objectives and targets relating to supporting the development of renewable generation.

In response to this National Grid noted independent analysis² that indicated that the pre and post BETTA transmission charges would be broadly neutral in terms of overall charges. In addition, National Grid believed that any mechanism to assist renewable for wider objectives outside the Transmission Licence should sit outside GB charging arrangements. Recent work commissioned by the DTI on the impact of transmission charges indicated that they would have very little influence on the development of onshore renewables³.

The GB charging methodology and subsequent amendments are judged against the relevant objectives in National Grid's Transmission Licence. Promoting renewable generation in support of wider objectives could not be shown to improve the charging methodology against the stated relevant objectives and could be considered as discriminatory.

Respondents to the GB charging consultation also indicated that National Grid should set up a working group to further develop proposals in relation to renewables. National Grid noted that it has for a long time held the TCMF through which it discusses development of the GB charging methodologies.

National Grid has also established the CISG group to enable industry experts to discuss future developments in GB charging methodology. National Grid notes that both of these forums are well attended by developers and industry participants with interests in renewable developments. Discussion at these forums has not provided any new evidence or raised any new issues that would lead to taking forward a methodology change.

² NERA report and addendum commissioned by Scottish Power available on the National Grid Industry information website

³ Adjusting Transmission Charges for Renewable Generators in the North of Scotland, a DTI consultation.

4. GB SQSS

The GB SQSS covers a number of areas, from the connection of generation; the requirements for the main interconnected system; through to the minimum connection requirements for demand. The principle focus of the GB SQSS is to provide a secure and economic transmission system. Application of the GB SQSS deterministic assessment identifies the minimum level of transmission capacity to support demand security. However, it does not automatically follow that the transmission system is designed only to meet this minimum level.

The GB SQSS does allow intermittent generation to be considered at a lower availability level in the deterministic assessment of the main interconnected transmission system boundary capacity. However, this deterministic boundary capacity, the 'required transfer' level, only sets the minimum capacity requirement. Where this required transfer level is not provided the appropriate licensee would need to apply for a derogation.

The GB SQSS also recognises that the efficient level of investment may not always be that provided by a deterministic capacity assessment based on system peak, and requires that other factors, such as the ability to cope with year round conditions, are taken into account when assessing the necessary and economic level of infrastructure.

For the purposes of this report it is important to understand that the deterministic standard is only used to ensure a minimum level of capacity is provided. This feeds through to ensure consumers receive a minimum level of quality and security, consistent with historic levels. The actual process used to determine the minimum capacity is relatively simple and is itself currently under review.

The GB SQSS also includes an economic assessment process. This facilitates licensees planning and developing an economic and efficient as well as a secure transmission system. Under the current commercial framework the economic assessment leads to similar levels of capital investment for both conventional and intermittent generation.

5. Deterministic assessment

This section describes the deterministic assessment that forms part of the main interconnected transmission system criteria in the GB SQSS. In summary, the deterministic assessment looks at the boundary capacity for groups of demand greater than 1500MW on the England and Wales system and the boundaries between the systems of SPT / SHETL and SPT / National Grid at peak system demand.

The first step in the process is to define the generation background. To do this contracted generation is reduced to be equal to the level of peak demand. This provides the balance of demand and generation in system zones and therefore a system boundary flow. A safety or security margin known as 'interconnection allowance' is added to this transfer to take some account of non-average conditions (e.g. power station availability, weather and demand). This is then compared to the actual capacity across the boundary in question to identify the need for reinforcement to ensure a minimum level of security.

The minimum boundary capability established through this deterministic process translates to a minimum level of demand security. In many cases this minimum level will not be the most economic level if it leads to large operational costs e.g. Balancing Services. This situation can arise for a number of reasons, such as: the system peak demand is not always the most onerous condition, the need to provide access to the system; or the rights that users have are financially firm (when the access is not provided compensation must be paid).

Appendix 1 provides an example of how the deterministic assessment is carried out. This demonstrates that wind generation is effectively scaled by 60%, low merit generation is completely removed and other generation is scaled by 83% (100/120).

It is worth noting that generation does not necessarily contract for TEC equal to registered capacity. In these cases the application of generic availability factors may be inappropriate. For example, if a 100MW intermittent generator contracted for 70MW TEC, a 60% factor would lead to it being modelled at 42% of registered capacity. The appropriateness of treating different types of generation in different ways is one of the main areas of focus for the current GB SQSS review, in particular how this impacts on security of demand.

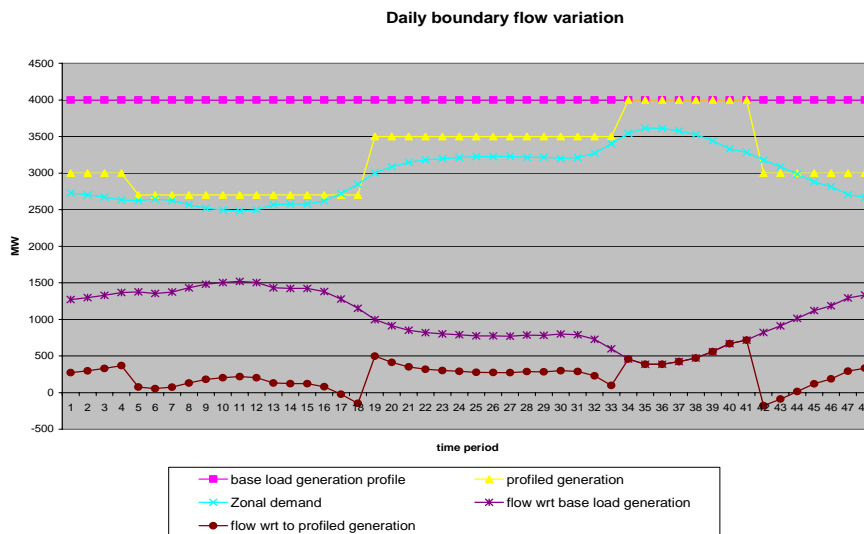
Use of system charges are based on TEC and not registered capacity, so a user self-calculating the optimum capacity requirements at 70MW (for a 100MW generator) would only be charged the zonal tariff multiplied by 70MW. This would be similar to optimising the capital cost of the turbine against other elements of a development. Clearly, this is an assessment that each generator itself has to make and under the current framework only a few generators have chosen to request a level of TEC lower than their registered capacity.

6. Year round issues

This section provides an introduction to some of the issues that are not covered by a peak demand deterministic assessment, but do need to be considered when planning a secure and economic transmission system. The focus here is not necessarily on intermittent generation, but more to highlighting the need for a robust year round assessment. In particular, highlighting that an over reliance on a winter peak demand deterministic assessment would not provide either a secure or an economic transmission system.

Boundary flow

In certain areas of the system, particularly export areas with a large excess of generation, periods of minimum demand can lead to flows that exceed those on demand peak. This occurs when generation in an area continues to run or does not shut down as fast as demand in the same area reduces. In some cases this leads to the export flow from an area appearing as the inverse to demand. This is demonstrated below:

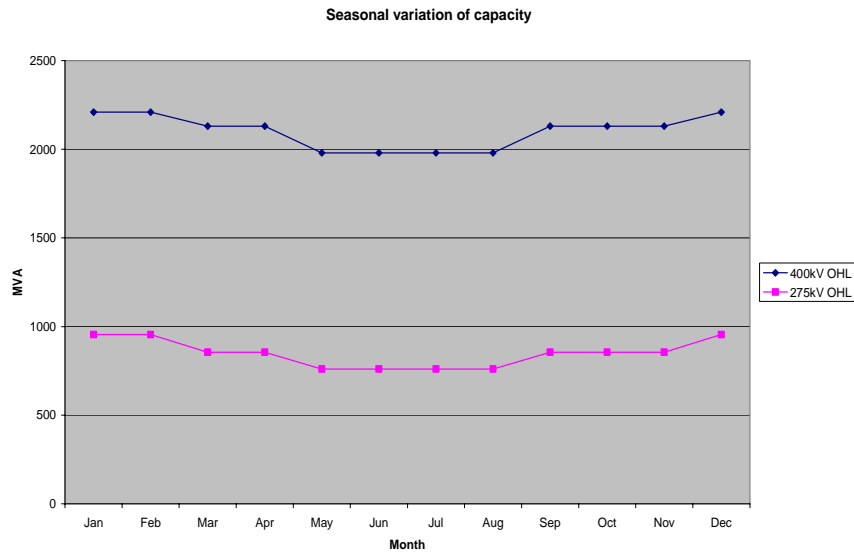


This shows that with a reasonably constant generation profile the maximum flow from an exporting area is not necessarily at the same time as the demand peak. Where an area is dominated by base load generation the peak flow is likely to be at the time of minimum demand. This can also be true in importing zones where the generation is marginal and the local peak demand occurs at a different time to the system peak demand e.g. the South West England. Even with a less onerous generation mix (profiled generation above) the peak flow can still occur at different times to the system demand peak.

Circuit ratings

On year round analysis this effect will be exacerbated by the fact that circuit ratings reduce in the spring, summer and autumn and that circuits are generally taken out of service in these seasons. The graph below

demonstrates the seasonal variation of capacity before outages are considered using generic ratings for two kinds of overhead line.



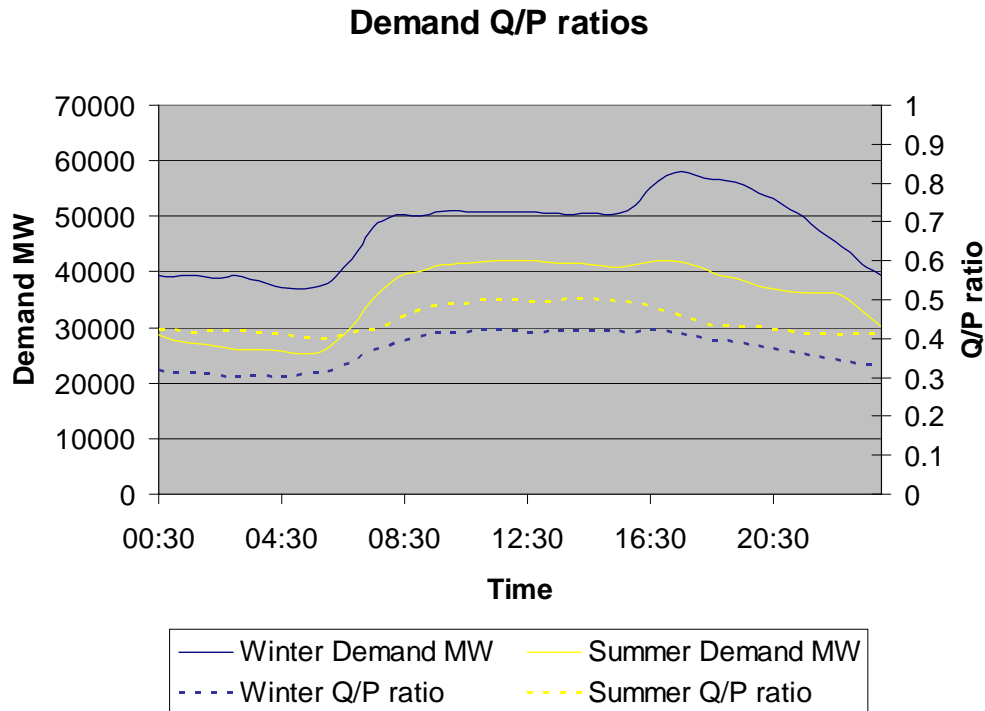
The GB SQSS also requires the system to be designed to cover situations that can reasonably be foreseen to arise in the course of year round operation. This would include off-peak and seasonal issues, typical forecast demand cycles, typical Power Station outages and typical planned outage patterns.

Removing transmission assets from service, even at times of lower demand, can result in the system not being able to facilitate all requirements for access without causing constraints to remove financial firm access rights. Removing a circuit from service will result in a step change to the access available on at least that boundary. For voltage and stability constraints the affected area could be significantly wider than the actual boundary the circuit route physically lies on.

Voltage and Stability issues

The most onerous voltage condition occurs with coincidence of the highest ratio of reactive power to real power (Q/P ratio), the highest flows on the transmission system and the least available reactive reserves. This combination generally occurs in the late morning, whereas the peak demand used for the deterministic standard is generally in the early evening.

The graph below, based on historic England and Wales data, shows how these profiles vary by time of day and season.



The graph shows that during the winter period the Q/P ratio is at the maximum in the morning when there is likely to be less plant synchronised to this system. This can cause problems when the marginal plant is situated in the same part of the system as the demand. It also shows that in the summer the Q/P ratio is significantly higher than in the winter i.e. voltage issues are more significant operationally in the summer.

The most onerous time for stability generally occurs when there is the least amount of generation plant connected to the system i.e. over demand minimum periods. This is because the fault level, which relates to a braking force on the system, is at its lowest overnight because the least amount of plant is synchronised to the system. This circumstance also occurs at the same time generation is most likely to be in the leading power factor mode, which is the least stable operating mode.

The need to meet the voltage and stability operational criteria, and possibly the fault level requirements can influence operational costs significantly if not taken into account at the design stage. For instance, it may be necessary to bring a generation unit on considerably in advance of the peak to meet the maximum Q/P ratio. In the case of stability it may be necessary to limit the operation of certain units off peak when the demand falls below a threshold.

7. Economic assessment

This section describes the year round and economic assessment performed under the GB SQSS, with a particular focus on intermittent generation issues.

Economic assessment seeks to establish the level of capacity associated with the minimum cost to the end consumer, taking into account all of the transmission licensees costs (infrastructure and operational). Current experience indicates that in most cases this will be greater than the level identified from the deterministic assessment. Recognising this, and that the fundamental plant mix and performance of plant types on the system is changing, National Grid has initiated a review into the assumptions made when establishing the minimum levels of transmission capacity.

Overview of economic assessment

Calculation of the economic level of capacity involves studying various scenarios that could reasonably be expected throughout a year, including variation to demand profiles, varying generation operating regimes, reasonably expected future generation patterns, the need for efficient and economic transmission circuit outages.

The economic assessment includes a number of operational costs including congestion costs, transmission losses and reactive utilisation costs. The economic assessment described below concentrates on congestion costs and is driven by the rights that generators receive through the CUSC.

The access rights can lead to compensation, the overall cost of which is determined by a combination of factors including the risk of the compensation occurring; volume to be compensated for and the cost of compensation. This compensation can take a number of forms: Balancing services contracts, bids and offers within the balancing mechanism or administrative payments through the CUSC (disconnection and inter-tripping).

The economic level of investment in infrastructure is established by comparing the net present cost of potential future compensation against the capital cost of increased infrastructure. For example, if the likely constraint cost is £3m per annum, but an investment of £10m would reduce this by half, the most efficient solution for end consumers would be for increased capital investment. This is demonstrated in the table below,

Option	Capital Cost (£m)	Compensation cost (£m pa)	Capitalised Compensation Cost⁴ (£m)	Total Cost (£m)
No investment	0	3	43.8	43.8
Reinforcement	10	1.5	21.7	31.7

⁴ Present cost calculated for a 6.25% rate of return over 40 years

Establishing the future transmission investment is obviously not this simple. Given the number of variables and the long lead times involved in transmission construction, assumptions about potential risks are captured through scenario analysis. Examples of such scenarios are provided in the Seven Year Statement⁵.

Appendix 2 to this report provides a simple example of how the issues below can be incorporated into an economic assessment.

Volume of restriction

Using reasonable outage patterns, along with scenarios for demand and assumptions regarding generation, a constraint (or compensation) volume (MWh) can be determined.

The volume will fall into two main categories, inherent and outage driven. 'Inherent' is where with an intact system under certain generation operational patterns constraints will occur; 'outage' driven is where a combination of transmission and generation outages will lead to constraints.

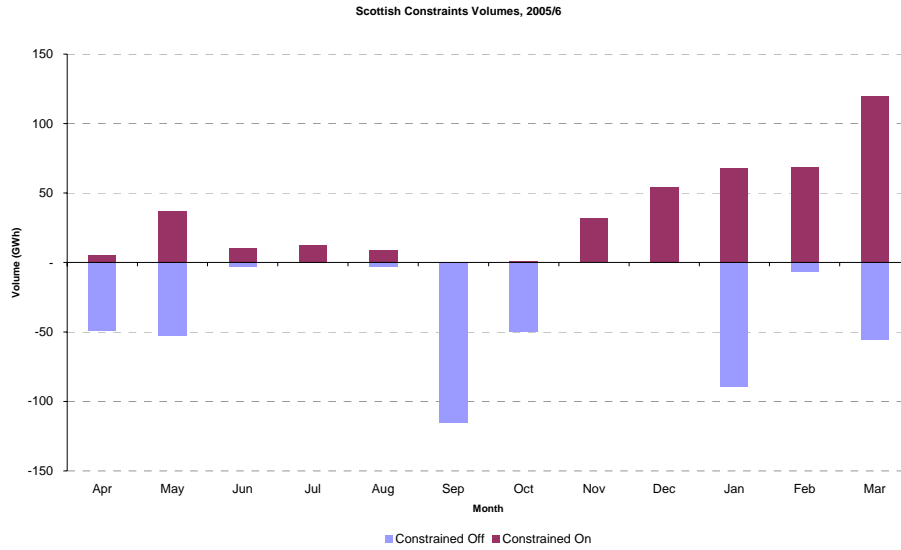
In the outage case the volume will not be spread throughout the year but will be concentrated in a short period. In other words, an economic assessment will take into account the likelihood of large constraint volumes caused over short periods of time, whereas this is not considered by a pure deterministic standard.

From a longer term planning perspective the output of an individual intermittent generator could be considered as more variable (i.e. likely operational state spread over a greater range) than conventional generation, along with a deterministic assessment that uses a low availability factor, constraints would be equally likely to occur throughout the year in the inherent as well as the outage scenarios if only the minimum capacity were provided.

In what would generally be considered a major exporting group, significant import constraints can and do occur.

⁵ Available on the National Grid industry information website
<http://www.nationalgrid.com/uk/Electricity/SYS/>

This volatility is demonstrated in the graph below:



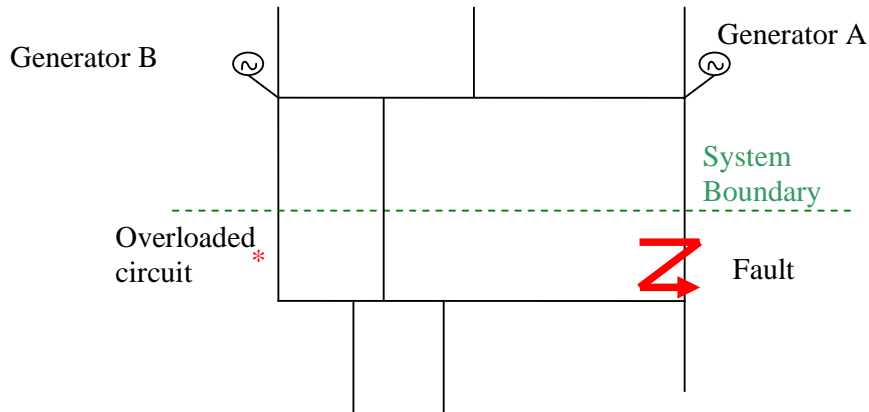
This shows the volatility of constraint volumes, indicating that in the same month both import and export constraints of significant volumes can occur; pure deterministic analysis fails to show this.

Even over the winter period, when the deterministic standard is actually applied, a group that is generally considered as exporting can experience significant import constraints.

Effectiveness

Where there is limited generation available within a zone or the 'effective' generation within a zone is limited, the unit cost experienced in resolving constraints can be considerable.

'Effectiveness' is used because within a zone not all generation can solve a constraint, this is particularly true for voltage and stability constraints. For a thermal constraint this is demonstrated in the simple example below:



In this example, due to the location on the system, reductions from generators A and B will not have the same effect on the overloaded circuit for a fault on the circuit below generator A. The effectiveness of each generator is established by reducing the output of each in turn by a nominal amount and recording the effect on the overloaded circuit. For example,

100MW reduction	Base case circuit flow MW	Post case circuit flow MW	Effectiveness %
Generator A	1700	1645	55
Generator B	1700	1683	17

This effectiveness will be different for pre fault and post fault conditions, because the impedances of the network change post fault.

The table below shows that in this example to reduce the flow on the overloaded circuit to 1600 MW, even if generator B has a lower bid price, generator A would be the most efficient choice.

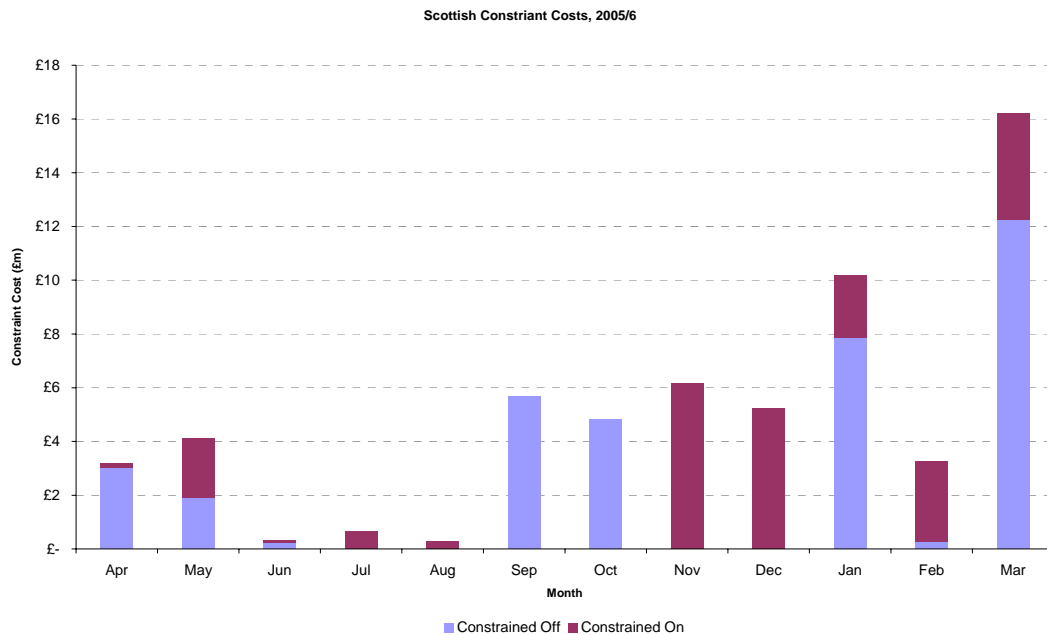
To clear a 100MW overload	Bid price (£/MWh)	Required reduction (MW)	Overall cost (£/h)
Generator A	45	180	8100
Generator B	15	588	8820

The example in Appendix 2 assumes a 100% effectiveness.

Total constraint costs

The total cost to the system of a constraint will be made up of not only the constraining-off cost (in the case of an export constraint leading to restrictions), but also the cost of replacement plant, or vice versa for an import constraint. However, the replacement cost is likely to be at the marginal market rate, so in most cases the constraining-off cost, in the case of an exporting constraint, or the constraining on cost, for an importing constraint, will tend to dominate the overall cost.

The graph below, which covers the same period as the constraint volume graph above, demonstrates how costs can vary.



This shows that even when the volume is approximately the same (i.e. October and March export from previous volume restriction graph) the actual cost experienced can vary significantly; in this case it more than doubles.

In the specific case of intermittent generation there are a number of particularly important additional issues. Firstly, the cost derived from the Renewables Obligation Certificate (ROC) will influence the constraint cost. In an exporting zone the cost to take off an intermittent generator will have to cover at least the lost ROC income. In an importing zone the generation would most likely be on anyway if the wind is available to gain ROC income.

Secondly, a considerable proportion of intermittent generation tends to be connected to the periphery of the system or centrally connected, but on spurs. In these circumstances the options for constraining plant other than intermittent is relatively limited, particularly in the off peak export scenarios. However, this would also be true in a zone dominated by intermittent

generation with only one flexible thermal unit, the value of the flexible unit could be very close to the lost ROC cost.

Granularity of Investments

A particular issue with investment for transmission is that capacity is delivered in large blocks. If a new connection point is required the rating of the associated lines is very likely to be a standard rating rather than specific to the actual project that initiated the investment. This concept of lumpiness is dealt with by having a smoothed charging methodology i.e. the tariff is established by an additional small increment and the charge based on requested capacity rather than installed capacity.

This smoothing is accepted on the basis that on balance the benefits of improved competition and stability in charging it delivers outweighs any downside associated with less specific investment or project costs. This is important on two levels, firstly the actual charge is based on a requested capacity and any adjustment to the charging regime to recognise reduced delivered capacity also undermines the use of a simple tradable access product. Secondly, the linkage in charging is to TEC, a subjective reduction to TEC for a particular class of generation without a more fundamental review of the other rights and obligations would appear to be inequitable to the treatment of other generators i.e. should the equivalent rights prevail when they are associated with a discount.

Operating regime

In reviewing the year round position significant differences between conventional thermal plant and intermittent generation is expected to be in the operational regimes. It is worthwhile noting that there is very limited data on operational regimes for intermittent generation. Nevertheless, there are a number of issues that are expected to be relevant in determining the annual operational cost. Here we do not identify every difference, but only the ones that have a direct influence on operational costs that can be mitigated through additional infrastructure capacity. For instance, any increase in short term contingency is not discussed.

Conventional thermal generation, if available, would be either off or on; if on, it would likely be a high load factor; if off, it is assumed that it could run and therefore contribute to security. On the other hand, if intermittent generation is available it is expected to be on, albeit at a very much lower load factor. If off, it is likely to be unavailable and so cannot contribute towards security. For example, a conventional thermal unit of 100 MW may come on in the morning, run through out the day and shut down some time after the peak. In the case of an intermittent generator it is likely to be on for the full 24hrs but at a much lower percentage of peak capability, however for a significant percentage of the time, 20 to 30%, it could be expected to generate greater than 60% of maximum output capability (depending on location).

The annual load factor of wind, which makes up the majority of intermittent generation, is very different to conventional thermal generation. Within the GB SQSS one would expect that if conventional thermal plant was available it

could contribute maximum capacity when required. However the GB SQSS assumes that wind may only be available for up to 60% of output (N.B. This only considers contribution to demand security and not any cost of restriction).

On this issue it is important to note that the deterministic assessment looks at the relationship between interconnection capacity and security of demand rather than the absolute availability of generation to export. Even at peak demand with a fully intact system, when an intermittent generator is at higher than assumed output there could be an active constraint. This would be accepted in the deterministic standard since sufficient plant should be statistically available in the importing area to cover any restriction in intermittent generation in the exporting area (ignoring the cost issues). To summarise, reinforcement of the transmission system to meet the requirements of the deterministic criteria does not lead to a constraint free system.

The volume of constraints is established by the probability of the difference between the generation and demand within an area exceeding the required transfer capability. When this risk is combined with the operating issues discussed above, this leads to a significant level of constraints.

Local works

It was noted earlier that the main interconnected transmission system deterministic criteria only applies to demand groups of 1500 MW and larger and across the SPT / NGET and SPT / SHETL ownership boundaries. Below this level and on the spur connections to the main system the capacity provided will be sufficient to allow export to the contracted level i.e. TEC.

These local works are planned in accordance with the generation connection criteria contained in the GB SQSS. As with the main interconnected transmission criteria, the generation connection criteria includes both a deterministic minimum and the option to design to a higher standard provided there is an economic justification.

The deterministic part of the generation connection criteria requires that the generator being assessed is set to maximum output (TEC), and therefore leads to the same level of investment for both intermittent and conventional generation. In addition, whilst the intermittent generation in question is at maximum other intermittent generation situated locally is also likely to be at or near maximum output. These local costs, such as substation works, can make up a considerable proportion of the overall cost of connecting a generator; however this proportion will vary depending on location.

In terms of intermittent generation the important point is that for local works and both conventional and intermittent generation would be treated exactly the same.

Access Rights

When a generator applies for use of the transmission system it requests a capacity, Transmission Entry Capacity, or TEC. The transmission system is then designed to accommodate that TEC. In the case of the GB SQSS deterministic assessment this is still worded in terms of registered capacity. However, in carrying out an economic assessment National Grid would consider the TEC for planning system investments.

The link between rights and compensation, and hence the efficient level of infrastructure, is that the right drives the compensation required in circumstances of under investment.

In granting TEC to a party National Grid provides financially firm access to the system i.e. if access is restricted compensation will be paid. There are several different forms of compensation ranging from a direct trade where a generator would agree not to export over a specific level (thus excluding the payment of energy); accepting balancing services in the balancing mechanism; through to payments made under the CUSC for not providing the access in real time (disconnection compensation).

Although the deterministic standard results in a 60% output for intermittent generation, this is related to the level of security for demand users. As noted earlier in this report the deterministic assessment does not cover the economic implications for users should the generator exceed 60% and potentially cause a constraint.

In some cases generators have chosen to request TEC for a level which is less than the registered capacity of their intermittent power station. In these cases the economic assessment would justify less capacity above the deterministic level as the level of rights are lower. This is then reflected directly to those users through lower charges. For example, a generator with a registered capacity of 100MW, but requesting a TEC of 50MW, will pay charges in relation to 50MW not 100MW.

Developers of intermittent generation generally request sufficient rights to be able to export up to the full output of the generator. It is providing the financially firm rights to facilitate this that leads to approximately the same level of transmission investment as for conventional generation. An alternative would be for the intermittent generator to accept or request a lower level of access (e.g. 80% full output capability), which would lead to a lower transmission investment and therefore lower transmission charges.

The example below illustrates this for a 100MW intermittent generator, assuming lost income in the range of £65/MWh, £45/MWh and £25/MWh from not generating at full output, located within a zone with a transmission tariff of £20/kW:

TEC	Transmission Charge	Lost income	Total Cost	Lost income	Total cost	Lost income	Total cost
	£20/kW	£65/MWh		£45/MWh		£25/MWh	
(MW)	(£m pa)	(£m pa)	(£m pa)	(£m pa)	(£m pa)	(£m pa)	(£m pa)
100	2	0	2	0	2	0	2
80	1.6	0.57	2.17	0.39	1.99	0.22	1.82
60	1.2	2.28	3.48	1.58	2.78	0.88	2.08

This is a very simple example and clearly excludes many other factors that a generator takes into account in its business plan and design. The volume of lost income is also highly dependant on the particular generator's load factor which is locational. The cost of lost income is taken as the volume times price for lost ROC and energy payments (both of which can vary).

The example shows that a generator with a low load factor could have an optimum TEC level lower than a generator with a higher load factor. Similarly, generator not receiving ROCs would have a lower lost income and so be less likely to request full capacity. Conversely, the size of the ROC payment drives the generator to request a higher than otherwise economic level of TEC.

The example indicates that there is a theoretically optimum level where it is more efficient for the generator to request a level of TEC below Registered Capacity. In this simple example a generator should theoretically only request around 80% of Registered Capacity as TEC (access right) if the cost is £45/MWh, therefore saving £400k pa in transmission use of system charges. In such cases the risk of constraints is reduced and so the infrastructure installed based on economic assessment would also be less. This highlights the importance of access rights in driving investment costs.

Whilst the generator has information to estimate the potential saving from purchasing capacity, the transmission companies have little access to the potential cost of not providing the access. In fact, the generator has a significant influence on the cost of any constraint. Where the generator is in a region with limited options for managing access restrictions, the potential constraint cost in real time (paid to the generator) could be far in excess of any saving by the generator in purchasing a lower TEC. This would suggest it is may be more efficient for end consumers if additional capacity is provided for new generators rather than being exposed to buy back of capacity.

Transmission Outages

Statistically the constraint risk associated with outages is difficult to assess as it can often only occur for a short period of time, however during that short period the cost could be very expensive i.e. low incidence but high impact.

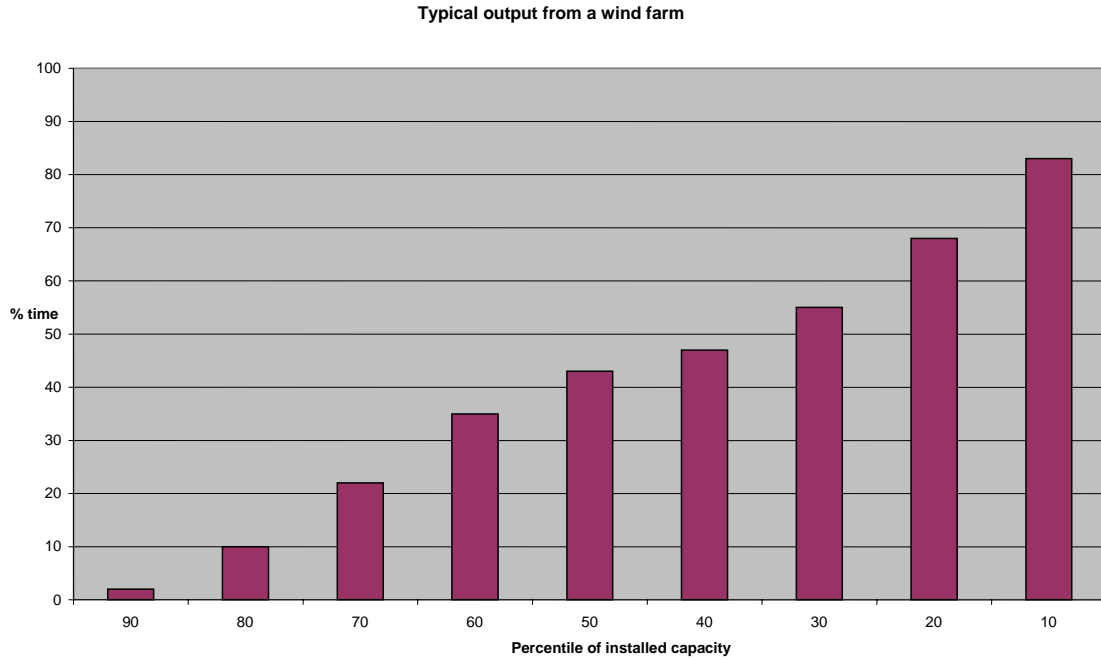
In planning outages of transmission equipment the transmission owner and the system operator will always seek to minimise any consequential restriction on generation, as this is the most economic solution and restrictions can also impact on local and wider system security.

In longer term timescales the potential constraint volume associated with an intact network is easier to quantify than under outage conditions and more suited to analysis by deterministic or probabilistic techniques. However, as the deterministic analysis generally provides a non constrained scenario at peak (for conventional generation) the costs associated with this are likely to appear much lower than scenario based analysis. For example, probabilistic analysis of the output against intact capability may determine a volume of 2000 MWhr of constraint throughout the year (a 0.6% restriction for a 100MW unit at 35% load factor). However, a 2 week outage causing a restriction for only 8 hours/day would lead to nearly 4000 MWhr restriction alone ($0.35 \times 100 \times 8 \times 14$). At a cost of £50/MWh (price of ROC and lost energy income) 6000MWhrs of constraint equates to £300k. In terms of capital £300k @ 6.25% and over 40 years the equivalent investment is £4.4m in real terms, two third of which is driven by outages in this example.

This demonstrates that with low volumes of inherent constraints the transmission outage situation could dominate investment decisions. In many of the economic assessments for new investments outage driven volume is largely ignored on the basis that licensees would seek to avoid it. However, it can be a significant factor in the timing of connection works.

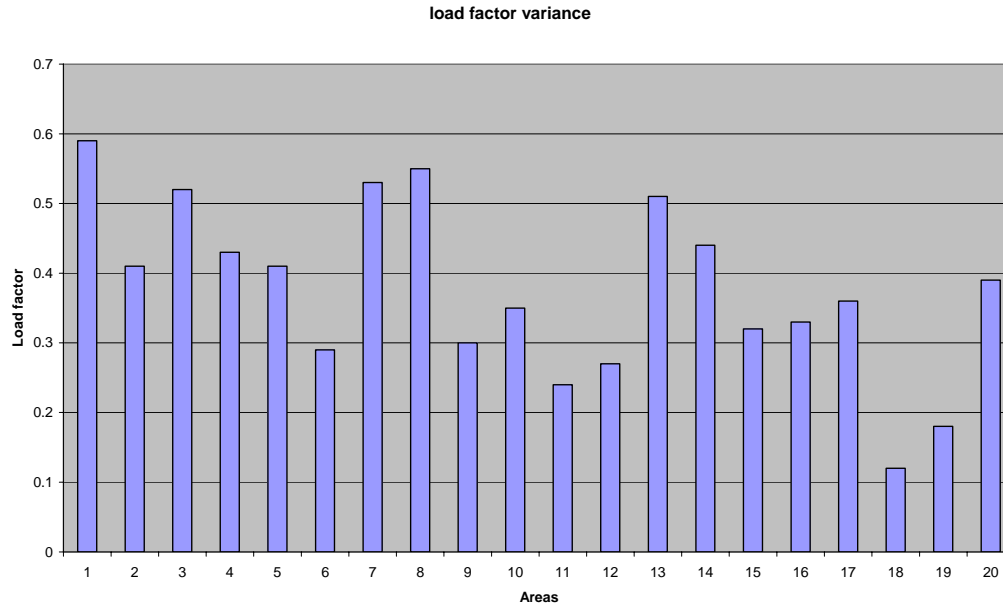
Load factor and volumes

Load factors vary depending on the particular type and location of generation. The best information available for a particular location would be used when determining the overall volume of constraints for a specific project. The graph below shows some generic data used in the examples in the appendix.



This shows a unit running for in excess of 80% of the time, with a load factor in the region of 40%. However, for more than 20% of the time the output is higher than 60%.

The table below shows the variance for a selection of locations from across Great Britain. The load factor range here is from nearly 0.59 through to just over 0.12, the generally accepted normal load factor will be in the region of 0.35.



Other considerations

Where a constraint is activated then the System Operator would need to restrict plant. The choice of which plant within an area to constrain will be based mainly on effectiveness (discussed above) and bid price, however there are other factors.

Within a zone it may not be viable to restrict the least cost unit as it is providing other services, such as local voltage support, Black Start availability or response services (both high and low frequency). In some cases the cheapest generator may already be selected to inter-trip (automatic post fault reduction of output) so a pre-fault restriction would have no effect, with the assumed post fault contribution having to be replaced elsewhere within the constrained zone.

Another important factor would be margin considerations i.e. the ability to meet maximum demand. This relates closely to effectiveness. The volume of restriction required on a generator could often be two to three times greater than the overload on the boundary, e.g. 3 times for a 33% effectiveness ignoring replacement plant. When the overall plant margin is low it would not be acceptable to restrict high volumes so more expensive plant with a higher effectiveness would be restricted.

In the case of other constraints, voltage and stability, there are similar issues to consider, where removing the lowest cost unit would actually increase the restriction or cause other restrictions elsewhere.

Cost of constraints

In terms of the actual £/MWh cost used in the economic assessment this is clearly subjective. National Grid uses a range of costs that take on different scenarios. For instance, if the only generator that could be restricted was an intermittent generator, then the cost is likely to be influenced by the costs of ROCs. If there was only one thermal generator in the same group then the cost may be slightly less than the cost of ROCs. If there were a range of generators available and all were reasonably effective, then cost could be very much less.

The discussion on TIRG⁶ works and also the recent Ofgem consultation on transmission licensees price controls indicate a range of likely costs for constraining plant off. These are⁷:

- Renewable generators associated with ROCs, typically £70 / MWh until 2027 and then £35/MWh
- Other renewable generators, typically £29/MWh until 2027, and then £35/MWh
- Conventional generation – a range of £10 -15/MWh

Importing groups

There are different issues in relation to importing groups. In terms of security of demand, a lower load factor would mean that it is necessary to provide a higher level of transmission investment to the local group. Although the wider investment cost (other than local connection works) is more likely to be linked to deferred load growth rather than actual investment required for connection (i.e. a future saving).

In the case of specific one-off generation developments the practice would be to assume no contribution for the purposes of security. However in assessing multiple generation developments economic analysis would be performed with some contribution from intermittent generation. As mentioned earlier this would be done for a range of scenarios to assess the full impact i.e. to assess the risk of having to purchase high merit plant that would not normally run. This is one of the main areas under consideration in the GB SQSS review.

⁶ Transmission Investment for Renewable Generation

⁷ Taken from Transmission Price Control review 2007-2012: Third Consultation, Ofgem web site

8. Questionnaire

In May 2005, National Grid issued a questionnaire seeking industry views on the issue. A summary of the responses is provided below, and a more detailed summary is attached as Appendix 4. The original questionnaire and all the non confidential responses are available on the National Grid's industry website.

The main points we concluded from the questionnaire were:

- Users recognise that conventional low load thermal plant could also be considered as intermittent, indeed all plant is intermittent to some extent.
- A common view was that intermittent is renewable type plant that does not have full control over its primary fuel source, to the extent that it cannot plan to run a maximum output at times of peak demand.
- Respondents were split on whether the charging methodologies should be modified to take account of intermittent generation.
- Recognition that any adjustments may be linked to the definition of the right to use the transmission system.
- Any adjustments purely on the fact that plant was renewable would be discriminatory and unlikely to better meet the charging objectives, suggesting that any review would need to be based on SQSS assumptions for renewables or on other attributes such as load factor.
- To be cost reflective the signals need to be derived from investment drivers, primarily SQSS.
- A review of load factor would go beyond the requirement of Condition 3.
- Those respondents who supported a review believed the options to be considered should be:
 - reviewing the generation level modelled in the transport and / or tariff models; and
 - a partial or full commodity based charging for generation

Commodity charging

Many respondents to the questionnaire suggested a move towards a commodity based charge, £/kWh, rather than capacity based, £/kW. This would allow intermittent generation to pay for only what they used. We do not believe such a change would better meet the charging objectives on basis of discrimination (which does not facilitate competition) and the loss of longer term signals. It does not represent a forward-looking incremental cost approach that is the basis of the current methodology. Additionally, it fails to provide incentives for firm long-term investment signals.

Notwithstanding these points, there appears to be no robust reason for allowing only 'intermittent' generation to pay charges on a commodity basis. If such a charge were introduced it would need to be applied to all types of generation in a non discriminatory manner.

A wide-scale move to commodity based charges would lead to a loss of longer term investment signals for National Grid. This would be against a background where the regulatory regime is seeking improved and firmer transmission investment signals.

National Grid also believes a commodity charge would be less cost reflective as investment is driven by capacity requirement (for a generator expressed in TEC) rather than a usage requirement. We note that in some cases this capacity may or may not be required on the demand peak; however the right and the capacity are both linked in an annual charge period for the maximum capacity required in that year.

The commodity element of the NHH demand charge is set such that National Grid recovers the correct revenue after calculating the HH charge. Therefore if a similar process was applied to intermittent generation, for instance if there was a 60 / 40 split in capacity / commodity charge, the 40% commodity would recover the same amount as the equivalent 40% capacity charge would have. This could also have a negative effect on other users since usage is less predictable than a contracted capacity and there will be large volatility in revenue recovery.

Providing capacity to meet peak demand scenarios generally drives investment in the transmission system. Therefore any move away from capacity based charges, in part or full, would result in less cost reflective charges. Whilst an intermittent generator may not be able to export maximum output at demand peak, they are statistically more likely to export high output over the months when demand peaks occur compared to other times of the year.

The charging arrangements are cost reflective and so linked to the investment process, the economic element of the investment process is driven by the rights under the CUSC. Therefore the charging arrangements are strongly influenced by the rights. Changing only the charging arrangements would not change the rights or the level of investment. As stated earlier, once the rights and risk of constraints are considered, the level of investment for intermittent generation is approximately equivalent to conventional thermal in most cases.

If the access product itself or the associated rights were to change this could have an influence on investment, at such time National Grid would need to consider the appropriate charging arrangements for that product in the context of the relevant objectives of cost reflectivity and facilitating competition in generation and supply. It is important to note that these objective need to be balanced, and any implied change due to a reduction in infrastructure would need to be assessed and against any consequential effect on competition.

The governance of access products comes under the CUSC and so is not considered in this report which was established under C4 of National Grid's transmission licence.

Modelling in the transport and tariff models

Analysis has been carried out on the effect of modelling intermittent generation in different ways in the transport and tariff model. This was achieved by adding 1000MW of generation to the tariff and transport model in discrete blocks, this was then gradually reduced in each in turn. The modelling assumed that intermittent generation is weighted towards the north. Appendix 3 provides more details of the scenarios used and the results.

When the generation charging base is reduced (in the tariff model) the generation tariffs change, but the absolute differentials do not change. The way in which generators are grouped leads to zonal differentials changing slightly. The weighting assumption also leads to the tariffs increasing slightly in the north and south (in the south becoming less negative to ensure correct revenue recovery). As the locational distribution becomes more even the change in the tariffs reduces.

When the generation is scaled in the transport model both the demand and generation tariffs change. Although due to the complexity of the DC load flow the change is not as linear as that observed in the tariff model. Given this locational weighting, the general trend was that the differentials are reduced as less generation is modelled. The demand differentials also change in a similar manner, although in the opposite direction and taking account of the misalignment between generation and demand zones.

When the change is applied in both the transport and tariff models both the generation and demand tariffs change, although the more significant effect is on demand. The generation differential fluctuates slightly depending on the amount of generation modelled, but overall the increase through reducing the charging base in the tariff model is virtually cancelled out by decrease through lower differentials. On demand, as the generation tariff element has no impact, the overall effect is that demand tariffs increase with more generation. As generation is reduced more in the north the demand charges increase more in the north, however the effect in the south is very much less.

Whilst it would appear logical to model any reduction in both models, it is the demand signals that appear to change most, albeit by a relatively small amount. However, given the main conclusion of this report not to take forward changes to the methodology neither option is will be taken forward so more detailed analysis or indicative charges have not been produced.

9. GB SQSS review

National Grid is currently carrying out a review of the treatment of various categories of plant in the GB SQSS. Clearly the treatment of intermittent generation within the GB SQSS is a major factor in future investment.

As discussed with the industry we have noted that should the GB SQSS review lead to any change in the investment process National Grid would then need to carry out a review to identify any consequential impact on the charging methodologies. Any changes to the GB SQSS following the current review are not expected to conclude within Condition 3 timescales.

10. Summary and conclusion

In accepting the GB charging methodology the Authority placed a number of conditions on National Grid. Condition 3 covered the treatment of intermittent generation within the charging methodology.

National Grid discussed the issues at the Transmission Charging Methodology Forum and agreed a review process. National Grid consulted with the industry through a questionnaire to gather views on the treatment of intermittent generation and possible alternatives. Following this National Grid discussed the issues raised at a number of industry charging meetings.

National Grid have reviewed the industry responses and carried out a review of the processes that lead to transmission investment, principally stemming from the GB SQSS, including comparing the processes for a conventional generator and an intermittent generator.

Through consultation and discussion the industry raised some interesting issues and the respondents were reasonably evenly split on whether the methodology should be changed or not. However, many of the issues raised related to the wider charging and access arrangements or were founded on the assumption that the whole planning process was dominated by a main interconnected transmission system deterministic standard.

Having reviewed the planning standard and being mindful of National Grid's wider licence obligations, particularly non-discrimination, National Grid can find no evidence that intermittent generation consistently causes less investment on the transmission system than conventional generation.

Investment for intermittent generation is currently being driven by economic assessment. Both the economic and deterministic assessment are covered under the GB SQSS. Economic assessment seeks to minimise the total cost of transmission, that being made up of the capital cost of providing infrastructure and the cost of withdrawing the access rights.

So whilst it is true that intermittent generation does not provide an equivalent contribution to peak demand security it does require equal access to the system, requested as a level of Transmission Entry Capacity. It is the consequence of providing financially firm access, and not the requirement to meet demand security criteria, that drives the economic level of transmission investment. Indeed, in importing groups the lower contribution to security (capacity credit) could possibly drive additional transmission investment. However, in this later circumstance National Grid does not believe there is sufficient evidence or experience to justify discounting the contribution of intermittent generators to security through higher tariffs (i.e. removing the positive offset provided, through the ICRP methodology).

Under cost reflective principles, the charge for use of the system and hence the level of infrastructure required will only reduce if elements of the associated access rights are also effectively reduced.

Therefore National Grid does not intend to propose any modification to the methodology in respect of condition 3. However, National Grid acknowledges that the whole issue of connecting intermittent generation is a developing area and National Grid itself has initiated a review of how individual types of generation are dealt with in the GB SQSS. In addition, due to the pressure to meet overall government targets for connection of renewable generation the issue of access to the system is currently being discussed in a number of forums.

Should the review of the GB SQSS lead to a change in investment planning or different access arrangements for intermittent generation be developed under the appropriate governance arrangements National Grid would be required through enduring licence conditions to review the impact of such changes on the GB Charging methodology.

Appendix 1 Deterministic Criteria

Example of deterministic standard

The example below demonstrates the calculation of the minimum transmission capacity using the method described in appendix C of the GB SQSS.

The first step in the assessment is defining the system and calculating the contributory generation in each zone. The example below uses a system with two zones.

	ACS demand (restricted) (GW)	Thermal Generation (GW)	Renewable Generation (GW)	Total Generation
Zone 1	5.5	11	2	13
Zone 2	56.5	65	2	67
Total (incl losses)	63.364	76	4	80

The system above has a plant margin of 26%, or 22% if intermittent is assumed to only contribute 40% to plant margin. This includes losses at 2.2%.

Where the plant margin is above 20% a 'ranking order technique' for scaling generation is used to bring the margin to 20%. This involves removing the power stations least likely to be running at peak. In this example we have taken the least likely plant to be thermal.

In this example 1.56 GW of thermal generation would be removed by ranking order. This has been applied evenly across the zones in this example; in practice it could be located in a single zone. This adjusts the thermal generation to:

	Total	Thermal
Zone 1	12.75	10.75
Zone 2	65.69	63.69
Total	78.44	

The total capacity, 78.44GW, represents a 20% plant margin assuming wind contributes 40%.

The next process is to scale all the remaining generation to meet the peak demand. This is where different treatment of thermal, hydro and wind is introduced by use of an 'availability factor'. This example ignores hydro and assumes that all intermittent generation is wind with a TEC equivalent to registered capacity.

The availability factor used for wind is 0.72, whereas for thermal it is 1.0. The 0.72 figure is chosen as it converts to 0.6 when the scaled to meet demand with a generation margin of 20% ($0.72 \times 0.83 = 60\%$). Note the plant that has

previously been removed through merit order effectively has an availability factor of 0.

The availability factor for intermittent generation used for importing groups is set to zero to reflect that intermittent generation is not relied upon to meet demand.

Availability factors (A)

	export, Z1	import, Z2
Conventional	1	1
Renewable	0.72	0

Applying the above availability factors this results in generation of:

	ACS demand (GW)	Contributory generation (GW)	Contributory conventional	Contributory renewable	P conventional	P renewable
Zone 1	5.62	12.75	10.75	2.00	8.97	1.20
Zone 2	57.74	65.69	63.69	2.00	53.19	0.00
total	63.36	78.44	74.44	4.00	62.16	1.20

Appendix D of the GB SQSS describes the calculation of interconnection allowance. This calculation is performed below.

Using this formula the interconnection allowance on the boundary between zones 1 and 2 in the above example can be calculated:

Interconnection Allowance	
Transfer from zone 1 to zone 2	4.56
Sum demand and generation in zone 1	15.80
Twice ACS peak	126.73
Sum of demand and generation in smaller zone over twice ACS peak as a percentage	12.47
IA as a percentage of total ACS peak	2.14
IA *peak ACS demand	1.36
Required transfer (planned + half IA)	5.23

In this example the minimum transmission capacity under the 'required transfer' condition is 5.23 GW. If the transfer capacity provided on the system is less than this a GB SQSS derogation would be required.

Appendix 2 Economic Assessment

Example of economic assessment

This is a simple example of how economic analysis would be performed. In practice the data used would be more detailed and where available site specific, also there would be many more scenarios looked at to reflect the year round possibilities.

In this example we have assumed the only balancing actions available are from intermittent generation. This is more likely to be the case for infrastructure closer to the project being reviewed. More detailed analysis would be performed looking at the various possibilities for resolving the constraint including other types of generation.

The first step in the analysis is to determine a volume of constraints. In order to do this the data required is the demand in the area, the system capability and the likely generation scenario. The required transfer would be that established for groups of 1500 MW or more (or on the SHETL/SPT and SPT /NGET boundaries), in the case of local works this would be the existing system capacity with the minimum changes to meet the generation criteria (section 2 of the GB SQSS).

In this particular example we are assuming that the inherent average transfer before development is 1.5 GW with an intact system capability of 2GW. The generation development is 2GW which causes an increase in the required transfer of 1.1 GW. The table below shows the system and the possible restrictions.

Wind Output	100%	80%	60%	40%	20%	0%
(GW)	2	1.6	1.2	0.8	0.4	0
Required Transfer, RT	3.1	3.1	3.1	3.1	3.1	3.1
Transfer for other plant	1.5	1.5	1.5	1.5	1.5	1.5
Total transfer	3.50	3.10	2.70	2.30	1.90	1.50
Constraint Volume (GW)	0.40	0.00	0.00	0.00	0.00	0.00

In order to calculate the 'Total transfer' in the table above the probability for generation is required, in this example we have used the probability below.

Output (%)	Probability
100-80%	0.05
80-60%	0.1
60-40%	0.15
40-20%	0.2
20-0%	0.5

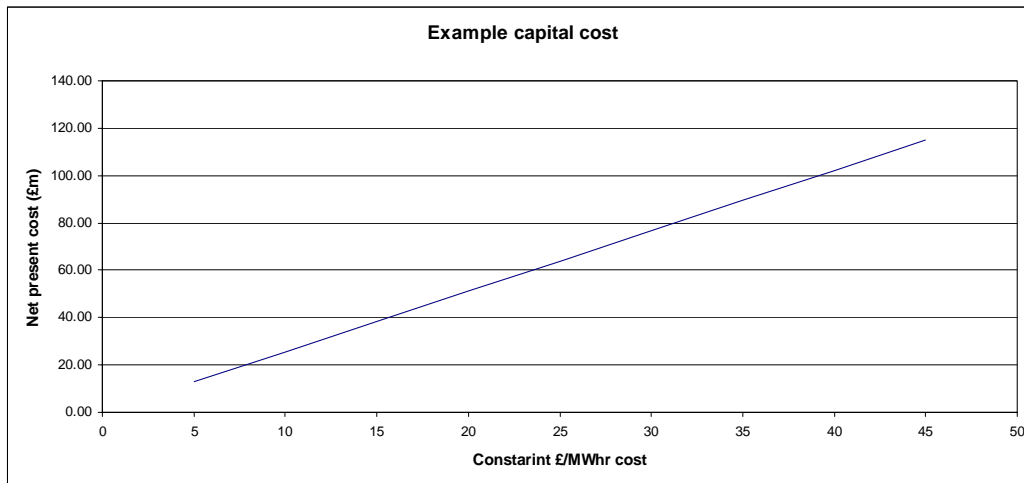
The lower probabilities, below that assumed in the deterministic standard are unlikely to cause a constraint for a compliant system. For outage conditions there may be a constraint at lower output, however we have not included that risk in this example.

In this example it can be seen that the only time that any restriction is active is when the output is in the upper percentiles 80% to 100%. This volume could be higher if all the thermal generation was running in that zone or other factors, such as those discussed in the main body of the report, were active. It could also be lower; however in this example the above represents a central scenario. In practice a number of generation and demand scenarios would be looked at.

In practice more detailed analysis would be performed with the load curves for different times of day and season, which would then be weighted. In addition far more analysis would be carried out on various scenarios of background generation to establish a weighted output.

The above 0.4GW restriction would be converted to a volume using the above probabilities, this converts to 175 GWh of constraint annually. In practice the analysis would be carried out separately for each season.

The next step is to convert this to an annual cost and then a capital cost. In this example the conversion is assumed for a 40 year life at 6.25%. The actual cost of constraints will depend on the many factors discussed in the main report. The graph below shows how the total capital cost can vary with the £/MWh cost assume for constraints.



This cost will then be used to establish an optimum level between annual constraint costs and capital expenditure. In this example no account has been taken of operational constraints or construction issues. Taking the cost of £40/MWh above indicates that there would be a net present value of £100m. Iterative developments would then be included to optimise the capital cost with the constraint cost i.e. the position when the sum of capitalised constraint cost and the capital investment cost are at a minimum.

The optimisation is dynamic and there is not a constant relationship between cost of infrastructure installed and reduced constraints costs. The impact of any new infrastructure would be assessed on system models and then the resulting impact on constraints would be identified.

The same calculation is also performed for each thermal generation project. However, because the deterministic standard would have set the minimum capability at a higher level and the cost of a constraining a thermal unit is lower, the actual additional investments is unlikely to be significantly higher than that established by the deterministic standard.

In some scenarios, where the cost of the constraint is large, then the actual capacity installed on an economic basis could be higher for intermittent generation than for thermal plant. This optimisation is dynamic and very dependant on the location and existing infrastructure, so relates to specific projects.

Appendix 3 Transport and Tariff model

Assumptions

Base network: revenue, expansion constant and security factor unchanged (based on 2005/6 charging model).

G:D split set as 0:100, this was in part because we were looking at this as part of condition 1 and also it makes analysis of the results easier. Although the absolute results would be different with a 27:73 split, the differentials are the same.

The generation was modelled as category C in the transport model to avoid further reduction by scaling.

In the base study 100MW of generation was added to:

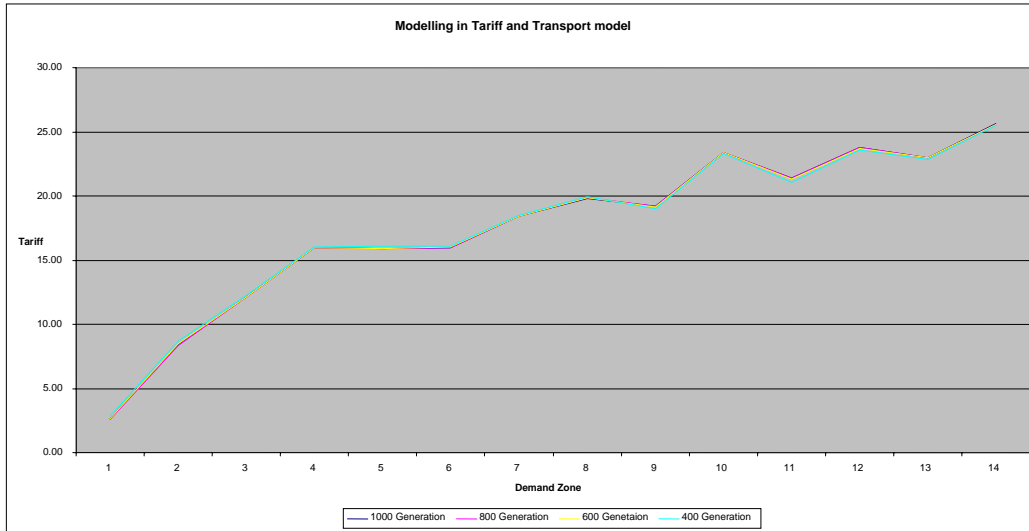
Heysham 400, HEYS4
 Coylton 275, COYL2
 Carradale, CAAD1Q
 Rannoch, RANN1Q
 Dunvegan, DUGR1Q
 Mossford, MOSS1Q
 Bora, BROA1Q
 Boat of Garden, BOAG1Q
 Fort William, FWIL1Q
 Fasnekyle, FASN10

In the tariff model the reduction was modelled by reducing the charging base, in the transport model the category c generation was reduced

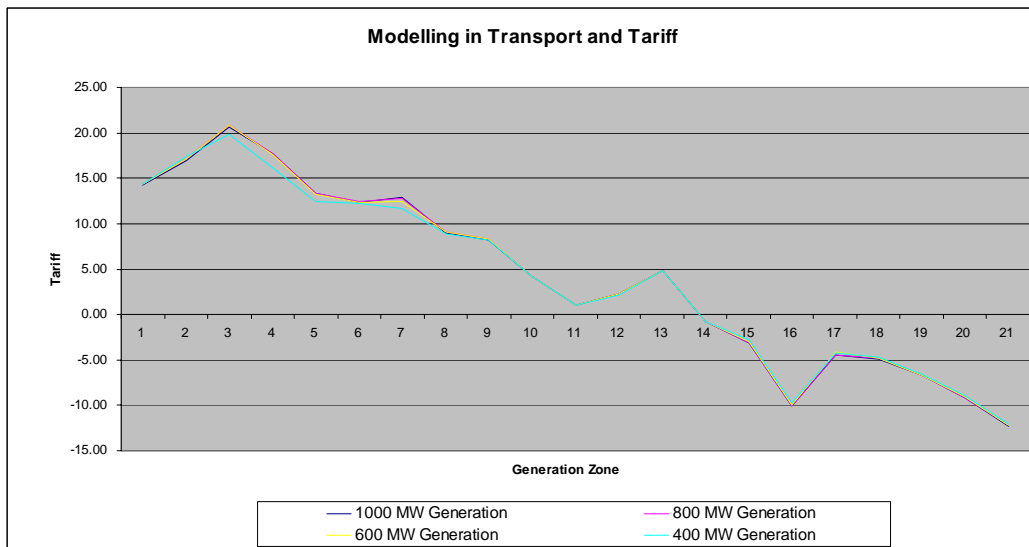
The studies performed were:

	Tariff model					
	Charging base					
Transport Model		1000 MW	800 MW	600 MW	400 MW	0 MW
Category C Generation	100%					
	80%					
	60%					
	40%					
	0 %					

The graphs below show the overall effects for a number of the scenarios.



The above graph shows the overall affect on demand tariffs. The main impact is on zones in the south due to the locational dispersion of the additional generation.



The graph above shows how the generation tariffs changes as more generation is modelled. Overall as more generation is modelled the differentials increase very slightly, although this effect is mainly due to the location dispersion used in the study.

Appendix 4 Responses to industry questionnaire

This appendix provides a summary of the of responses to the questionnaire, copies of all response are available on the National Grid industry information web site.

There were 15 responses to the questionnaire, only one was marked confidential.

Q1 Please can you provide your definition of intermittent generation including your rationale?

General definitions or statements provided were,

- 1) Generation whose output varies due to physical constraints.
- 2) All generation is, in fact, intermittent in that it does not generate all the time
- 3) Output becomes restricted for reasons other than market or system conditions. It could be applied to other low LF generation.
- 4) All generation not running at base load.
- 5) All generation is intermittent. Attempting to distinguish on grounds of an arbitrary definition of intermittence is unhelpful and potentially discriminatory.
- 6) Any criteria should be unambiguous and related to physical operating characteristics on a site specific basis.
- 7) Any generating unit that does not have complete control over its primary fuel source.
- 8) All generation is intermittent, but for different reasons.
- 9) Should include all renewable technologies which do not have a constant fuel supply, and CHP with limited control over output and possibly some hydro units.
- 10) Generation that produces a variable level of output over a fixed period of time and depending on prevailing weather conditions.
- 11) All generation that does not operate continuously.
- 12) That generation which is subject to naturally occurring variations in the availability of its energy source over which the generator has no control.
- 13) In the absence of despatch instructions to modulate its output provides a variable output between zero and full load depending on weather conditions (excluding CCGTs).

There were two extremes in the responses. Where intermittent could describe all generation and where it does (or should do in the context of charging) describe generation that is weather limited and / or not fully controllable. The exact definition of weather limited and not fully controllable appears to be debatable.

Four respondents believed that all types of generation were intermittent to a greater or lesser degree. One respondent commented that all generation was intermittent in the sense that it does not generate all the time and few generators are ever able to use their full TEC everyday. Another respondent commented that some generators are limited by factors such as availability of water where other generators have operating patterns.

Two respondents suggested that focus on the perceived definition of intermittent generation is unhelpful, both noted that all generation could be considered as intermittent.

Two respondents suggested intermittent should cover all low load factor plant with no explicit linkage to the controllability or type of primary fuel.

Five respondents linked the term intermittence in some way to the ability to control the primary fuel source. Three of these made a discrete linkage to weather. Other respondents noted that factors other than weather could be considered.

Q2 Do you believe that the existing charging methodology should be modified to account for intermittent generation?

Six respondents indicated 'no' and seven indicated 'yes'. Of the seven that indicated yes, three indicated that any change to arrangements should also include low load factor plant.

Of the 'no' respondents four stated that the infrastructure needed for intermittent generation needs to cope with the possibility that it will be generating at full output at winter peak. Generators had indicated the right they require and that right drives peak costs. Two respondents noted that to change the methodology for low load factor generators would be discriminatory or indicate a lower level of access product. One respondent suggested that any attempt to modify the methodology for intermittent generation could lead to an unjustifiable dilution to the cost reflectivity principle. Another respondent indicated concern any changes would give rise to other unwanted effects e.g. incentives not to run at end of year to reduce load factors.

One respondent noted that all generation should be treated in a consistent manner and the methodology could be modified to reflect the fact all generation is effectively intermittent.

Three respondents suggested that the methodology should be changed as the existing methodology does not recognise the fundamental distinctions between intermittent and non-intermittent generations. Two of these respondents defined the differences as being the low load factors and lack of control to generate at full capacity. The other respondent noted that the current charging methodology assumes that all generators are equally able to utilise their full TEC at the time of peak demand, this is not the case for intermittent generation who cannot choose to generate to their full TEC at system peak.

Other comments in favour of a review indicated the costs should be linked to how TEC actually drives investment in planning, taking account of the likelihood of plant generating, and that the charges could more accurately

reflect practice. There was concern that capacity based charging disadvantaged low load factor plant and that a charge based on usage may be more appropriate.

Q3 What changes would you propose for intermittent generation in the charging model (e.g. scaling in the transport model or the use of merit order approach, commodity charge) and how would you justify your proposals?

The main proposals for change were for in the area of scaling and move towards a more commodity based charge. No respondents supported a merit order approach for modelling of generation, mainly on concern of how the merit order would be derived and undue influence this may have on the market.

A number of respondents raised other issues that are not covered here as they go beyond the scope of this questionnaire e.g. transmission access, connection and investment process and wider government / local initiatives. However, several parties noted the charging methodology should be consistent with the principles applied and assumptions used in investment planning (i.e. cost reflective). It was also noted that there was a linkage to the actual definition of the right to use the system (i.e. possibly of non-firm access above the normal charging capacity) and that along with planning decisions there could be an impact on constraints where higher than forecast output occurred.

Several respondents supported scaling of the capacity used in the charging model to more accurately reflect the usage at demand peak. A number of respondents suggested that any form scaling should be applied to all types of generation to avoid any discrimination. Similarly, it was also suggested that a charging figure other than TEC, which more accurately reflects usage, should be used in the charging model.

Several respondents also supported moving away from an exclusively capacity (£/MW) charge in favour of either a combination of capacity and usage (commodity £/MWh) charges or a wholly usage charge. A number of these also supported this approach along with scaling of generation contribution in the charging model. The main benefits suggested were that it would better reflected actual usage of system and the effect of the type of the plant on the system. A usage charge would also avoid discrimination, treating low load factor plant all the same.

The respondents who did not support a change did not support either scaling or a move away from a capacity based charge in the short term. The main reasons given were the possible discrimination of scaling and a move away from the primary investment driver (i.e. less cost reflective). However, it was suggested that some form of scaling or facilitated trading could be developed in the future.

Q4 Do you believe that your proposals for intermittent generation should be applied to other types of generation?

Based on the response to previous questions (no change) three respondents indicated that Q4 was not applicable.

The majority of respondents indicated that in order to avoid discrimination that any change to the charging methodology should be applied to all generation i.e. based load factor rather than type of generation.

One respondent also suggested that, given the number of changes to the charging methodology in the recent past, a period of stability in charges would be beneficial.

Two respondents believed that any changes to the scaling should be applied exclusively to intermittent generation, both of these respondent considered intermittent generation to be those where the primary fuel source was affected by weather or factors considered outside the control of the generator. However, both of these respondents indicated that a change to a more commodity based charging regime should apply equally to all types of generation.

One respondent considered that application to plant other than what it considered intermittent outside the scope of this questionnaire and so should be considered separately.

Q5 Do you think your proposals would have an impact on embedded generation and why?

Based on the response to previous questions (i.e. no change) three respondents indicated that there was no impact on embedded generation. Respondents commented that specific embedded generation issues were outside the scope of this consultation and so should to be considered separately.

However, a number of respondents recognised there would be an impact on embedded generation through the normal application of the charging methodology, but again this was a separate issue to intermittent generation.

One respondent noted that any proposed changes need to consider effect on embedded generation and be mindful of any inappropriate incentives that undermine the cost reflectivity of the charges.

Other respondents believed there would be an impact on embedded generation and this would result in more cost reflective charges, consistent with the effect of the proposed changes on directly connected generation.

One respondent noted possible changes in respect of embedded generation charging arrangements in the near future and indicated any effects of

proposed changes arising from intermittent generation should be consistent with these.

Q6 Do you believe that National Grid should await developments in the review of the treatment of intermittent generation in the GB Security of Supply Standards before proposing any change to the charging methodology in this area?

Six respondents indicated that a review of charging arrangements for intermittent generation should await the outcome the review in the SQSS. In addition two further respondents indicated it was not applicable as there should be no change to current charging arrangements. Five respondents felt that the review of charges should not wait until the SQSS had been reviewed.

Those that did not support waiting for the SQSS review suggested the TO invests to allow full level of generation so there was no need to wait. Two other respondents felt that there would be an interaction, but the reviews could be conducted in parallel. Another suggested a better way forward could be for the reviews to consider Main Interconnected System and non compliant parts of the system separately e.g. single circuit generation spurs.

One respondent indicated that irrespective of the SQSS review scaling and low load factor plant issues should to be considered in respect of charging.

The main reasons supporting the charging review to wait for developments in the SQSS were that operational and planning parameters should be consistent; the planning process defines the impact on investments that is signalled through charging; charging should not be looked at in isolation and it would appear sensible to wait.

Q7 Are there any other issues on intermittent generation that you wish to be considered?

The following additional comments were made:

- that alignment with distribution charges should be a consideration;
- the methodology for determining charges for embedded generation should be consistent with that for directly connected generation;
- that the discussions on Charging methodology as applied to Intermittent generation take into consideration other areas such as transmission access and treatment of EELPS etc;
- noting that failure to adapt the charging methodology to accommodate the particular characteristics of intermittent generation could jeopardise the achievement of Government renewable energy targets;
- consider connection arrangements based on the 'capacity factor', to align with new charging arrangements and revised SQSS.