AREVA

National Grid (fao Mr. William Kirkwilson)
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

London, 22 July 2010

Dear Sir,

NATIONAL GRID CONSULTATION DOCUMENT

Reference: GB ECM-19 Charging for large loss frequency response

Thank you for the opportunity to comment on the above reference. This note provides AREVA's views on the review of frequency response charging.

AREVA is responding as a technology vendor of nuclear power plants and in particular its EPR design which is already the technology of choice in UK for EDF Energy (who has plans for 4 EPRs on two sites) and is under active consideration by Horizon Nuclear Power for its UK nuclear investment programme. Thus our comments focus on the fundamental need for an equitable treatment of generation technologies, this being a prerequisite for a fully liberalised market.

As described in the background to your consultation, in September 2009 the SQSS working group concluded that the infeed loss limits should be increased to 1320/1800MW. AREVA agrees with this conclusion and the view that such changes will facilitate connection of units and inter-connectors in excess of 1320MW and, in parallel, address the issue of offshore systems.

Clarity on this SQSS change is important for investor certainty. Any decision to target frequency response costs due to this SQSS change has the potential to impact investment decisions in low carbon technologies and is therefore discriminatory. We note in particular that the SQSS working group considered the carbon benefits of the proposals and that these have been ignored in this consultation document.

In the Reference, National Grid outlines three options and states an intention to implement Option 2 – targeted costs by generator capacity. AREVA considers that to target charges to users based on size is discriminatory, anti-competitive and will significantly impact investment in certain technologies and size of plant. The rationale for Option 2 seems to be based on somewhat questionable estimates and assumptions, the outcome being that technology is discriminated by size or location.

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In contrast, Option 1, the continued socialisation of costs, is a non-discriminatory market based solution which gives an efficient economic ex-ante price signal to all market participants. Thus, the costs associated with frequency response are charged in the least distortive manner (which is the rationale for the current charging system) with costs being split 50/50 between generation and demand, and charged uniformly by MWh. Any change to this charging rule would distort the market inefficiently.

Thus AREVA considers that Ofgem should veto any decision by NG to implement Options 2 or 3 and maintain Option 1. Any change from this will be seen as being anti-competitive.

Yours sincerely

Jean-Jacques Gautrot,
President and CEO AREVA UK

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23rd July 2010

Dear Adam,

RE: National Grid's Consultation on Charging for Large Loss Frequency Response

Thank you for the opportunity to respond to this Consultation Document. This is a non-confidential response on behalf of the Centrica group of companies excluding Centrica Storage Ltd. As stated in the January pre-consultation, Centrica is opposed to the proposed move away from a socialised to a targeted model of recovering Frequency Response costs. We believe that these proposals would be detrimental to the UK electricity market, do not have any precedent, and would not result in National Grid better meeting its objectives.

Our views can be summarised by the following:

- These charges are linked only to generation size and do not consider the probability of a trip and as such are not wholly cost reflective;
- National Grid's focus on one element of balancing costs is too narrow and creates inconsistencies;
- Existing generation plant would be unable to respond to this price signal which would damage competition;
- The ex-post nature of proposals and the significant number of variables at play make an accurate impact assessment very difficult;
- Frequency Response represents a wider good from which all parties benefit equally and hence it is logical that these costs should be socialised;
- These proposals go against the logic of the GB SQSS decision to raise the loss limits

which was taken to allow larger generation units to connect to the network on the same basis as others;

- Targeting the costs of Frequency Response would act as a significant disincentive on developers to build large low carbon generation at a time when investment is essential and would impede the UK's emission reduction targets.

Below, we have provided a detailed response as to why these proposals would lead to National Grid being less able to meet its objectives and as such should be rejected by Ofgem if National Grid opts to take these proposals forward.

Facilitating effective competition

Rather than improving competition, these proposals can be shown to have a detrimental impact on existing competition with operational generation captured by these proposals unable to respond to the price signal, or indeed hedge this cost in any way. We believe that these proposals discriminate against certain generation types more generally. For example, given that it is only really viable to build comparatively large nuclear generation units – and given this generation type would not be able to respond to the price signal – it would therefore be unduly detrimentally impacted.

National Grid argues that a capacity charge represents a transparent methodology for apportioning costs between Users, as each User will have their charges calculated by the same formula. However, although the calculation may be transparent, the number of variables in play makes this information on its own almost meaningless (e.g. in order to form an estimate of their exposure, Users would need to know beforehand the exact size and number of generators running, the cost of National Grid's actions to provide the response and total demand). Furthermore, given the large number of variables and the ex-post nature of the charge, it is not possible to accurately assess the impact of these proposals.

National Grid states that it would provide a within day data stream in order to mitigate the difficulty users would experience in forecasting these charges. However, the economics of nuclear generators are such that they function on a must-run basis and are unable to respond to a within-day price signal. We believe that this discredits National Grid's claims that this particular option facilitates competition.

Cost reflectivity

Centrica believes these proposals would not represent an improvement to cost reflectivity. The provision of Frequency Response represents a wider good to the system (as do services such as Black Start and Reactive Power); all parties benefit equally from this provision and hence it is logical that these costs should be socialised. National Grid approaches this from the view that the connection of >1320MW generators will directly lead to an increase in response costs of £110 million to deal with the risk of a large generator trip. However, this assertion is based on some incomplete assumptions. Risk is defined as a combination of impact and likelihood. The calculations used here to arrive at the charges are directly linked only to size (impact) and as such do not take into account the probability of this type of generation tripping. We believe this to be a significant omission when assessing the cost reflectivity of these proposals and do not understand why large generators have been singled out in this way.

We also disagree with National Grid's proposals that generators under 350MW should not be captured because, as National Grid states, a minimum of 350MW of response is maintained to cover dynamic frequency changes for demand. Currently these costs are socialised between generation and demand. However, under these proposals demand and <350MW generation

are treated differently as demand will continue to pick up 50% of the incremental cost but not <350MW generation. This does not appear to be cost reflective.

Centrica also believes that there are some serious anomalies within the resulting calculation. In particular with regard to option 2, the model provided with the note of clarification published on 5th of July assumes a 100% load factor for most of the generators running, whilst scaling back a proportion of the generators to meet the demand requirements. However, the result of this in the model is that >350 MW generators which are running at part load (e.g. 10%) are picking up a targeted BSUoS cost whilst the actual risk they pose to the system does not fall within the targeted bands.

Developments in UK generation mix and transmission

As the UK moves to a low carbon economy it will need to substantially increase its nuclear and renewable fleet. Although both these generation technologies introduce new challenges for the GBSO, in the form of different response and reserve requirements, they also deliver **significant wider societal benefits** and are fundamental to the UK meeting its legally binding environmental obligations.

We do not believe that National Grid's proposals take into account developments in both generation and transmission. National Grid argues that this proposal has been put forward in response to developments in the SQSS which is being developed alongside changing generator technology. However, National Grid's proposals represent discrimination against a subset of generators which undermines the SQSS objectives. The GB SQSS took a decision to raise the loss limits to allow larger generation units to connect to the network on the same basis as others. We would also note another anomaly in that the SQSS limits have been raised in the past without any associated charging changes because it has evolved to accommodate advances in generation technology. In addition, focusing only on one element of balancing costs, namely response and not reserve, is too narrow and creates inconsistencies

Other considerations

As well as the points raised above, we believe that there are other aspects of these proposals that would be deleterious to the UK energy industry. Centrica believes that targeting the costs of Frequency Response would result in investment uncertainty and act as a significant disincentive on developers to build large units at a time when investment in additional plant is essential to maintaining the UK's security of supply.

In this respect, it is also questionable whether the charging methodology should have a determining effect on the size of investment. As well as having a negative impact on security of supply, these proposals could compromise the UK's ability to meet its carbon reduction targets would lead to a perverse incentive to build smaller generation with all of the potential efficiency losses and planning and security issues.

I hope these comments have been useful. If you want to discuss any element of this response, please do not hesitate to contact me on 07789 579169 or at Ricky.Hill@centrica.com.

Yours sincerely,
Ricky Hill

Industry Development Analyst
Centrica Energy

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FAO Adam Sims
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19th July 2010

Dear Adam,

GB ECM-19: Charging for Large Loss Frequency Response

Drax Power Limited ("Drax") is the operating subsidiary of Drax Group plc and the owner and operator of Drax Power Station in North Yorkshire. In March 2009, Drax acquired an electricity supply business, Haven Power Limited ("Haven"); Haven supplies some 27,000 small and medium sized business customers and provides an alternative route to market for some of Drax's power output.

Drax welcomes this opportunity to respond to National Grid's consultation document regarding charging for Large Loss Frequency Response. Drax continues to disagree with the National Grid stance on charging for Large Loss Frequency Response, believing that there is not a sufficient justification for the proposed changes.

Maintaining the security of the transmission network is a service that the System Operator provides for the benefit of all Users. Ensuring that the transmission network remains stable is crucial from an operational, economic and social perspective, regardless of whether the Users of the network are domestic consumers heating their homes, industrial and commercial businesses manufacturing products and trading merchandise, or energy businesses involved in the generation and trading of electricity. As all Users rely upon a secure and reliable transmission system, regardless of size, all Users should share the burden of maintaining the system's security.

It could be argued that the current socialisation of Response costs acts as an industry insurance policy to ensure that the network is stable and reliable for the benefit of all direct and indirect Users of the transmission system. The socialisation of such costs also appears to be the correct option to encourage much needed investment in technologies that are, in turn, being encouraged by Government policy.

<u>Commodity Charges</u>

With respect to commodity charging, Drax welcomes National Grid's comments regarding the fact that a £/MWh commodity charge provides a transparent process for attributing costs to Users of the system and that such charges provide Users with the knowledge that they will receive the same proportion of costs as others using the system in any given period. Drax also agrees that such predictability in relative charges between Users is a benefit to competition.

However, the argument that a commodity charge does not allow Users to predict the charges themselves is unhelpful; it must be questioned how any of the proposed methodologies will help Users to predict such charges in timescales that are meaningful to generators. As an example, it is unlikely that forecasts of such charges under any methodology are going to provide signals on Response costs greater than one year ahead of time, when Users, particularly independent generators, attempt to trade within the wholesale electricity market to hedge their investment.

The hedging profiles of conventional independent generation plant dictate that sales of power will be transacted well in advance of National Grid providing "additional within-day data streams" on Response costs; such data provision is no mitigation for uncertainty. The knowledge that all Users face the same proportion of costs (as they do presently) provides greater certainty to generators, which, in turn, helps facilitate competition.

Capacity Charge

With regards to capacity based Response charging, the data required to forecast charges (listed in the consultation document) suggests that such forecasting for individual Users will be extremely complex, particularly when attempting to forecast costs beyond the within-day timeframe.

Given the complexity of forecasting charges and the fact that Users would not receive the same proportion of costs as others using the system at a given time (as it would depend on which plant, and the size of plant, that was running), the inability to accurately predict charges beyond the within-day timeframe does not help those generators that require the ability to hedge their assets (via the wholesale electricity market) multiple seasons / years ahead; this is a particular problem for independent generators. The difference in charges that Users receive in a given period could be the difference between making a profit and a loss on the day.

Further to this, such proposals appear contradictory to National Grid's previous views that the allocation of additional costs to generators purely on capacity, rather than performance, gives no signals to "change behaviour"; in this particular case, it could be argued that such a proposal would not encourage investment by Users to improve future performance and minimise short-term generation losses.

Banded Commodity Charge

The consultation document suggests that a banded commodity charge ensures all Users of a similar size are paying a similar charge per MWh, based upon their use of the system. As such, Users will know that they will receive the same proportion of costs as those units that are of a similar size in a given period, which is put forward as a benefit to competition. However, this is not the case, as size of unit does not necessarily correspond to type of unit; whilst it could be reasonably assumed that, given the information currently available, all new 1800MW units joining the system will be nuclear units, the same could not be assumed for gas, coal or biomass units in the lower bands. Hence, those units banded together may not operate in the same way or pose the same risk.

Furthermore, given that units using the same type of fuel could be assigned to different bands, the costs applied to such units could differ considerably, which would have a negative effect on competition. In addition, higher efficiency plant could potentially be banded in a higher cost bracket than lower efficiency plant of the same technology, which may have an impact on the environment.

As National Grid is aware, the Government is currently attempting to encourage businesses within the UK to transform the way in which they generate and consume electricity, with a key area of policy being a set of targets to dramatically cut the level of greenhouse gases emitted; it is clear to all concerned that attaining this target will require unprecedented investment in new generation plant, transmission infrastructure and consumer-side efficiency measures.

This proposal has the potential to discourage investment in innovative large-scale generation, such as new nuclear, offshore wind farms and CCS coal / gas plant; there is a need to ensure that the effect of banded commodity charges on such investment is considered against the potential benefits that National Grid claims the proposals would deliver. If the Government is to meet its environmental targets, it is imperative that investment in new generation technology remains attractive. Further to this issue, the suggestion that bands could be reviewed over time further erodes investor certainty.

Developments in the Transmission Business

If the proposals are aiming to target Response costs at those generators that create them, it would seem logical to pass additional costs to those types of plant that have less predictable output and regularly deviate from their Physical Notification. In the future, when grouped together as a technology type, the

short-term losses caused by certain types of plant that have correlated generation patterns could be more regular (and larger) than those from the large individual units targeted by this proposal.

It is disappointing that National Grid has failed to address the issue surrounding the cost of Response for changes in output from intermittent generation under the "Developments in the Transmission Business" section. The latest consultation document has avoided the question over whether intermittent generators should be expected to cover the cost of procuring plant to provide the Response required for changes in, for example, wind speed. Such signals could be achieved via the Information Imbalance Charge, which could be used to reduce overall BSUoS charges and allocate charges to those that deviate from their notified running profile.

Furthermore, and as mentioned in our previous response, it would appear that the inclusion of transmission spurs may have a large impact on clusters of projects that are developed at the extremities of the network, for example clusters of remote wind projects. This could have serious cost impacts to such generators and may result in projects being abandoned. However, it may seem reasonable to include transmission spurs containing such projects, as it is not purely plant faults that could lead to Response events, but also the potential for similar plants to be subject to the same conditions that cause them to lose load simultaneously (again, the example here being clusters of remote intermittent generation that are subject to the same conditions).

Conclusions

Drax continues to believe that maintaining the security of the transmission network is a service that National Grid provides for the benefit of all Users, regardless of size; as such, all Users should share the burden of maintaining the system's security on a socialised basis. Drax does not believe that National Grid has provided an adequate justification for changing the way in which Response is charged.

As identified in the consultation document, commodity charging provides a transparent process for attributing costs to Users, provides Users with the comfort that they will receive the same proportion of costs as others using the system at that time, and, in turn, such predictability in relative charges provides a benefit to competition. Whilst none of the methodologies will help Users predict charges in timescales that are meaningful to those hedging their asset seasons / years in advance, the knowledge that all Users face the same proportion of costs per MWh (as they do presently) provides greater certainty to such generators.

If you would like to discuss any of the views expressed in this response, please feel free to contact me.

Yours sincerely,

By email

Stuart Cotten

Regulation
Drax Power Limited

Adam Sims
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National Grid House
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CV34 6DA

23 July 2010

Dear Adam,

GB ECM-19 Charging for large loss frequency response – consultation document

EDF Energy is one of the UK's largest energy companies with activities throughout the energy chain. We provide 50% of the UK's low carbon generation. Our interests include nuclear, coal and gas-fired electricity generation, renewables, combined heat and power plants, electricity networks and energy supply to end users. We have over 5 million electricity and gas customer accounts in the UK, including both residential and business users. EDF Energy's networks business runs the UK's largest power network including both public and private networks.

We welcome the opportunity to respond to this consultation and have included our detailed comments as an attachment.

We agree with the SQSS working group conclusions which recommended a change in frequent and infrequent loss limits to remove a barrier to the timely connection and access of large generating units and other infeeds. The working group also conducted a cost-benefit analysis which demonstrated a benefit of £790m p.a. in carbon reduction (due to the connection of six large 1,650MW nuclear units) at a cost of c. £150m p.a. due to extra frequency response holding. It is clear that from an economic perspective this cost-benefit makes the case for the SQSS changes to be made. Indeed, our own analysis of a single year, 2020, using our long-term despatch model indicates that if the SQSS change is not made and the assumed large low carbon generation capacity is replaced by conventional generation, there is a significant increase in carbon emissions of 8.6 million tonnes at an additional cost of £ 261m.

We have significant concerns with National Grid's preferred charging solution (Option 2 – capacity) which targets frequency response costs on new and existing generators based on their capacity. We believe this is discriminatory and will undermine investor certainty in large forms of affordable new low carbon generation and as a result the above benefits

might not be realised. Given this targeted approach also disproportionately affects existing larger generating units this might therefore have security of supply issues for the UK as well as having a long term impact on the competitiveness of UK energy supplies.

We believe National Grid has reached its conclusions to target costs by ignoring the above benefits and by focusing on the c. £150m costs of making the SQSS change. Appendix 2 provides an overview from Poyry of analysis completed at our request using their 2009 multi-client intermittency study for GB and Ireland. Of particular note is the Poyry conclusion that the increase in infeed loss limits results in much lower additional costs of £37m in 2020 and an additional £52m in 2030. This is an important point as it is the c. £150m p.a. which has acted as a trigger for National Grid's decision to support a fundamental shift in the way frequency response costs are recovered.

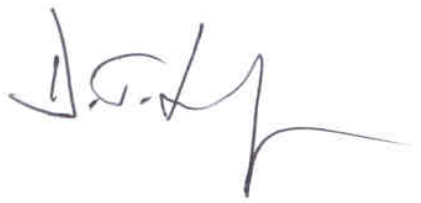
National Grid's conclusions are further biased by its inappropriate use of a narrow interpretation of its transmission licence obligations. Their narrow interpretation discusses 'cost-reflective' charges rather than charges which reflect the costs incurred by the system operator on users of the transmission system.

It would have been more efficient for National Grid to have considered this charging issue taking into account wider social and environmental objectives and benefits as held by Ofgem rather than solely focusing on its much narrower licence objectives. It is clear from the cost benefit analysis referred to above that the environmental benefits of a change in frequent and infrequent loss limits are substantial and should not be jeopardised by inappropriate and discriminatory frequency response charging arrangements.

We have numerous and relevant concerns with this proposal and feel strongly that Ofgem should use its power of veto to prevent the targeting of frequency response charging when it is assessed against its statutory duties.

If you have any queries on this response or would like to arrange a meeting to discuss further, please do not hesitate to contact my colleague Rob Rome on 01452 653170, or myself.

Yours sincerely,



Denis Linford
Corporate Policy and Regulation Director

Attachment

EDF Energy response to GB ECM-19 Charging for large loss frequency response – consultation document

EDF Energy welcomes the opportunity to respond to this consultation. The key messages of our response are as follows:

- We agree that the infeed loss changes to the SQSS should be made as determined by the SQSS infeed loss limits working group[1].
- This SQSS change is important for investor certainty and security of supply
  - The raising of the infeed loss limits will provide greater opportunities for all types and sizes of generators to connect to the transmission system in a timely manner and removes a barrier to diversity.
  - The change complements the recent DECC decision to implement a connect & manage socialised model of TAR (and veto of locational BSUoS) Any decision to target frequency response costs due to this SQSS change might undermine TAR and therefore impact investor certainty and security of supply.
- There are wider market and carbon reduction benefits for UK plc which were calculated by the SQSS working group. These have been ignored in this charging consultation which focuses on the forecast costs alone.
- Without sufficient justification, National Grid (NG) has extended its terms of reference and has considered all frequency response costs rather than to review 'extra' frequency response costs (forecast due to an increase in infeed loss limits). NG's proposals will affect charges for both existing and new GB generators but are not consistently applied to demand users.
- NG has made statements within this charging consultation which seemingly contradict views which were expressed in the final report of the SQSS review group.
- NG has developed two forms of targeted charging options and has assessed these against a narrow interpretation of their licence requirements. This is not sufficiently consistent with both their own statutory duty and those of the Gas and Electricity Markets Authority.
- The forecast costs of making these changes have been estimated by NG as £110m p.a. This is based on dynamic continuous response holding and is therefore likely to be severely overestimated.
- NG intends to implement Option 2 – targeted costs by generator capacity. Prior to proposing a fundamental change to the way in which frequency response costs are recovered we would have expected NG to have:

[1] The working group consisted of representatives of the three GB transmission owners, SHETL, SPT and NGET; a representative of the Authority and three generating company representatives, EDF Energy, Eon UK and British Energy. The Amendment Report was submitted to the Authority on 10 Sept 2009

- Performed a holistic review of the principles underpinning the recovery of frequency response costs.
- Provided a robust rationale for no longer supporting the current equitable charging basis of frequency response which exists due to the societal benefit of providing such a service to all market participants.
- Considered the benefits of making the SQSS change (c. £790m) prior to recommending an appropriate charging mechanism.
- Conducted an impact assessment to establish the effects of this charging change on all market participants.
- Taken account of wider market impacts (e.g. wholesale price and carbon reduction effects and competitive distortions) caused by their proposed changes.

- We believe that targeting all frequency response charges to users based on size is incorrect, discriminatory, anti-competitive and is likely to prevent investment in certain technologies of plant.
- If a targeted charge was deemed appropriate we would expect this to be a non-discriminatory market based solution which gives an efficient economic ex-ante price signal to all market participants. However, both targeting options derived and proposed by NG are:
  - ex-post rather than ex-ante.
  - unavoidable by market participants either by behavioural change or by employing a suitable hedging product.
  - discriminatory based on technology, size or location on the transmission system.
  - overly complex and are formulated using a large number of assumptions and estimates, some of which are flawed.
- NG's targeted options are not cost-reflective
  - Much of the frequency response costs forecast by NG will be incurred to continuously maintain frequency rather than arresting an occasional fall in frequency (e.g. due to the infrequent loss of a large infeed).
  - NG is directly linking the costs of frequency response with generator size alone and this is not the sole driver of these costs.
  - System frequency must still be maintained if no generating unit greater that 350MW is operating therefore a methodology which does not charge generators <350MW is incorrect.
- NG's analysis and methodology used to determine Options 2 and 3 is fragile and is based on a single unrealistic scenario.
- There is no impact assessment or consideration of unforeseen consequences and competitive distortions and no indication of proportionality in making this fundamental change.
- We continue to support Option 1 – continued socialisation of costs.
- We believe Ofgem should veto any decision by NG to implement options 2 or 3.

Introduction

This charging consultation is the third time the changes to the SQSS infeed loss limits have been the subject of industry debate. The first such consultation was held by the SQSS review group and resulted in a recommendation from the review group to Ofgem that the generation infeed loss limits be raised to facilitate the connection to the GB transmission system of generating units and interconnectors >1320MW. The review group's final amendment report also noted that the Authority may wish for a consultation on the charge-out of extra frequency response costs and a charging pre-consultation was published in December 2009. The clear, majority view of industry parties (representing a divergent set of commercial positions) was that there was no requirement to introduce targeted charges for frequency response as a result of the change in infeed loss limits within the SQSS.

Despite these recommendations and industry views NG has persisted with the development of targeted charging options. Having stated that the extra response costs are significant enough to warrant a review of charging arrangements NG has extended the scope of this issue from the extra frequency response costs (forecast as a result of the increase in infeed loss limits) to all frequency response costs. EDF Energy would be interested to learn what level of extra frequency response costs in NG's view would not have required a review of charging arrangements and we discuss NG's forecast increase in costs later in our response. NG also proposes to introduce their preferred option for targeting frequency response costs in April 2012. This date is in advance of when the relevant extra costs would be triggered i.e. by the connection to the transmission system of a potential infeed loss of >1320MW.

Investor certainty

The change to the infeed loss limits within the SQSS is a clear requirement for the security standards to evolve in line with developments in generation technologies. The raising of the limits will allow the connection to the transmission system of large units such as nuclear, CCS, interconnectors and offshore arrays, and result in wider transmission system design benefits. It would also allow smaller generators to connect to existing transmission spurs up to the new infeed loss limit. This avoids not only the investment costs of an additional transmission circuit but reduces the environmental impact of transmission and minimises any delays in obtaining appropriate planning and environmental consents. There are also technical benefits to system operation of the diversity of generators connecting to the transmission network; the change in SQSS infeed loss limits will remove what is currently a barrier to this diversity. However the benefit of investor certainty for all types and sizes of generators is being eroded by the narrow charging consultation from NG despite this change being fundamental to generation investment which will help deliver the UK's legally binding carbon and renewable energy targets.

These requirements were fundamental to DECC's determination on transmission access to allow the connection of generators ahead of wider transmission system development (Connect and Manage). DECC also determined that a socialised model for recovery of additional costs incurred as a result of Connect and Manage creates the best climate for investment. EDF Energy believes that a targeted cost recovery option for frequency response undermines DECC's determination on access.

Statutory duties and transmission licence requirements

NG's views of the charging options presented in their consultation are narrowly focused on their interpretation of the relevant objectives of transmission licence condition C5. EDF Energy believes that the scale of this issue warrants wider consideration within NG's overarching statutory duty to co-ordinate the transmission system in an economic and efficient manner. While the detailed licence requirements are intended to be consistent with this duty, there are important issues which are not captured by the objectives within condition C5. We note in particular the intention of the Energy Act 2010 to extend Ofgem's duties to include the reduction of carbon emissions and the delivery of secure energy supplies in its assessment of the interests of consumers. Ofgem of course already has social and environmental duties and none of these significant factors are reflected in the narrowly defined objectives within the transmission licence.

Wider benefits of the change to infeed loss limits

The SQSS review group considered a future scenario of connecting large nuclear units to the transmission system and the potential carbon benefits that those units might bring. This carbon benefit was calculated to be £790m[2] p.a. and crucially this is ignored by the charging consultation. While this was only one possible scenario the carbon benefits of large nuclear, CCS and offshore wind are all potential outcomes of the change to the infeed loss limits all of which have been disregarded in this consultation. Furthermore, there are potential market impacts of this change which although difficult to quantify these should not be ignored.

For the purposes of this consultation NG has re-visited the analysis completed by the SQSS review group which was part of the original assessment report on the proposal to change the infeed loss limits in the SQSS. It is NG's view that the information it presents in Table 3 of the consultation shows the total benefits[3] that should be assumed when considering the appropriate methodology for charging of frequency response costs. We note that this work includes the benefits to transmission system design should the infeed loss limits be increased. However we believe the benefits go wider than NG's analysis and that this important factor has been ignored within this consultation.

[2] p44 of SQSS review request GSR007 Amendment Report 10th September 2009
[3] Response £110.7m; reserve £46.2m; system design -£27.3m; total £129.6m

National Grid's cost benefit analysis

In our response to NG's charging pre-consultation, EDF Energy requested that a more accurate and first principles forecast of frequency response costs should be derived prior to the development any targeted charging options. NG has not undertaken this. Industry respondents, including EDF Energy also commented that different options to provide frequency response, such as static providers on low frequency relays might result in costs of a much lower magnitude. This has not been considered by NG for the purposes of this consultation.

Furthermore NG is proposing a fundamental change to existing charging principles without a robust assessment of the materiality of the issue and is relying on simplistic and potentially materially inaccurate methods of assessment. To establish the costs presented in Table 3 (discussed above) NG has made a number of assumptions. Regarding the forecast of additional frequency response costs four key assumptions were made, namely: (1) that there is a constant instantaneous loss risk; (2) the dynamics of providing frequency response is ignored; (3) the level of frequency sensitivity of a load is assumed; and (4) crucially the relationship between frequency response costs and requirements is assumed to be linear (despite presenting data in Figure 3 to the contrary). These are broad assumptions and estimates which give us great concern that the cost of £110.7m might be wholly inaccurate. Our confidence that this forecast is built on solid footing is undermined further by errors in the consultation, e.g. a total circuit saving of 165km seems to have been calculated from 11 circuits x 10km (later corrected to 11 circuits x 15km in a note of clarification).

EDF Energy analysis

Appendix 1 describes the analysis which we have been able to conduct within the timescales of this consultation period concerning a single year (2020). From these studies we have been able to draw three conclusions.

1. A delay in commissioning of new nuclear capacity, which is not filled by conventional technology (on the assumption that it will not be economic to construct a new CCGT to take advantage of a delay of only a few years) leads to increased power prices and increased carbon emissions. Our results indicate an increase in baseload power price of £2.40 /MWh, with consumers ultimately paying an additional £1060m in 2020.
2. If conventional capacity is constructed instead of new nuclear capacity, there is a significant increase in carbon emissions of 8.6 million tonnes or 6.7 %. These cost an additional £ 261m at the assumed market price.
3. The additional cost of creating headroom to accommodate units > 1320MW rather than those below the infeed loss limit appears to be over-estimated in NG's calculations. Our analysis indicates these costs might increase from £37m to £56.7m p.a. (compared with NG's extrapolated estimate of £110.7m). We believe it is a reasonable assumption that the cost of utilising reserve, i.e. response costs, will not

increase due to the larger unit size; it is the cost of creating additional headroom, i.e. upward reserve costs that are expected to change. This assumption differs from the consultation calculations, which show a linear increase in both costs (as discussed above).

Poyry Energy Consulting Analysis for EDF Energy

Appendix 2 provides an overview from Poyry of the analysis completed at our request using their 2009 multi-client intermittency study for GB and Ireland. Of particular note is the Poyry conclusion that the increase in infeed loss limits results in additional costs of £37m 2020 and an additional £52m in 2030. This increase is attributable to the additional cost of part loading plant.

Our internal analysis and that of Poyry's were conducted independently using two different sophisticated modelling environments. The additional costs in 2020 are £20m and £37m respectively. Neither of these figures can be associated with NG's extrapolation of 2009 costs resulting in their assumed incremental cost of £110.7m.

This is an important point as it is the £110.7m which has acted as a trigger for National Grid's decision to support a fundamental shift in the way frequency response costs are recovered.

National Grid seem to no longer support the existing charging arrangements
Our views on Option 1 – Commodity charge

The costs incurred by the System Operator in managing frequency response are currently recovered through Balancing Services Use of System (BSUoS) charges and under NG's Option 1this would continue to be the case. BSUoS is levied on both demand and generation split equally on a £/MWh basis. There are very good reasons why this is the case and none of these aspects have been discussed by NG in their consultation. All balancing services (including frequency response) are part of a service provided by the system operator to all users of the system; in this respect there is a wide societal benefit to a balanced and stable system. The logical and appropriate conclusion is that the costs of system balancing should be shared equally by demand and generation.

It is our view that NG needs to give greater consideration as to why it no longer supports historic decisions regarding the charging of BSUoS before it proposes a move away from the current arrangements.

Using targeted charges

EDF Energy described in our response to NG's pre-consultation our views on why targeting of charges is inappropriate and unreasonable. We now discuss these views again in more

detail noting that the following comments apply to both Options 2 and 3 in this consultation. We discuss these options separately later in this response.

Economic price signals for new and existing generators

NG has used a very narrow interpretation of cost-reflectivity when reviewing the current method for the allocation of frequency response costs. NG suggests that reflecting costs onto market participants (which are assumed to have been caused by those users) sets a level playing field for effective competition. Applying this logic to the costs of managing frequency response is fundamentally flawed for a number of reasons.

An effective price signal for a market participant must result in an appropriate behavioural response from that user so that the costs might be avoided or mitigated. The only ability a new generator has to avoid this targeted charge is to avoid investment in larger generation technologies or not to locate efficiently onto a transmission spur. The proposals therefore distort investment signals for future generation projects and drive inefficient investment decisions.

For those generators where investment decisions have already been made these targeted charges are unavoidable. NG's ex-post frequency response charge does not give the opportunity for a generator to respond to the intended price signal. The proposed methodology is complex and depends on the demand level and running arrangements of other generators. NG has demonstrated that forecasting frequency response costs is extremely difficult. As frequency response is procured on behalf of market participants by the System Operator the generator exposed to a specific targeted charge has no ability to hedge or mitigate this risk. It would also be impossible for any generator to forecast their charge as the costs are non-transparent. Any accurate forecast would require foresight of outturn demand levels and precise prediction of other generators' behaviour.

NG states in this consultation that industry support the existing methodology to recover frequency response costs though BSUoS is an "indirect indication that there is no appetite for response charges to be set ex ante". We believe this is an incorrect assumption. Industry might not require an ex-ante charge so long as frequency response costs are socialised. However, if these costs are targeted based on generator technology, size, or location then market participants would need to know what these costs might be on an ex-ante basis.

In its determination to veto GB ECM 18 (Locational BSUoS) Ofgem stated "ex post charges undermine the delivery of the anticipated benefits of the proposal in terms of providing cost signals to influence more efficient behaviour". It is clear to EDF Energy that this same argument applies to GB ECM 19 and therefore the proposal to target frequency response costs would not better facilitate competition.

Discrimination

NG's Options 2 and 3 incorrectly link generator size with risk and then introduce targeted charges to generators which discriminate based on unit size. Furthermore, Option 2 does not levy any charge on generators <350MW and Option 3 does not levy a charge on generators <300MW. Clearly such generators benefit from the balanced system which is provided to users through NG's actions to manage frequency, however, under Options 2 and 3 these generators would not contribute to the costs. Surely, if the GB transmission system had only 300MW generators connected, NG would need to procure frequency response for the societal benefit of a balanced system for both generators and demand.

Options 2 and 3 would distort competition in the energy market and would result in NG acting outside of their transmission licence which prohibits discrimination between users (Condition C7). NG's own data (taken from the Seven Year Statement and presented in Table 5) indicates that over 300 generating units (from a total of 401) would not contribute to frequency response charges as a result of Options 2 and 3.

It is also of note that any inequalities in the balance of competition between distributed generation and transmission connected generation will be further distorted by this proposal.

Nature of the risk and application of all frequency response costs to generators based on size

NG's decision to target frequency response costs is based on the assumption that the costs it incurs for frequency response are directly related to the sizes of the units which are generating at the time. This assumption relies on the belief that the risk to the system is directly related to generator size only. However, much of frequency response costs are incurred to continuously maintain frequency due to spontaneous changes in demand rather than arresting an occasional fall in frequency (e.g. due to the infrequent loss of a large infeed). Therefore if it were to be truly cost-reflective NG's methodology would account for this nature of the service which is being provided to all system users. Furthermore, as was discussed by respondents to the pre-consultation, the continual maintenance of frequency within a defined boundary is a prescribed level of service and cannot be influenced by system users. Neither of these fundamental points is addressed by NG's narrow assumption which relates cost to generator size only.

It was identified by the SQSS working group report that the connection of single generating units in excess of 1000MW (the normal infeed loss limit) does not appear to be 'special' in that it does not create risks for system operation that are different in character from at present. The entire basis of NG's decision to target frequency response costs is that the larger units do impose a 'special' impact which must be reflected in charging arrangements. This is clearly incorrect. While it may be true that the level against which NG must secure frequency will relate to the size of the largest unit generating, its

assumption does not capture the true nature of the risk to the system. The risk of losing a generation infeed is a function of many factors and not just the size of a unit. Reliability of both generation and the transmission system are important elements which have been ignored by NG. No targeted charge could accurately take account of the nature of these risks which further demonstrates the appropriateness of the existing shared recovery of costs through BSUoS.

There are further technical subtleties to the service of frequency response in that existing and future large steam-driven generating units have higher inertia than small modern technologies[4]. Without this inertia provided by the larger generators a greater amount of frequency response holding might be required.

It is also of note that in managing system frequency, NG benefits from the diversity of generators connected to the system which in part is achieved by Grid Code requirements on generators, for example to maintain power at times of low frequency.

Specific comments on Option 2 – Capacity charge

NG's preferred option to introduce a daily capacity based charge to generators >350MW is highly complex and over reliant on assumptions and estimates. The charge has been developed based on the assumptions described earlier used by NG to forecast additional response costs of £110.7m. The charge is based on frequency response curves (an example of which is provided in Figure 5) which are not transparent and relate to the complex half hourly activity of the system operator. This is something which can not be understood, managed, forecast or hedged by a generator; yet they are to be charged on this basis.

Specific comments on Option 3 – banded commodity charge

EDF Energy notes that this option does not receive the support of NG. We believe that this option was hurriedly developed. It uses a point in time derivation of banding of generators and apportions costs against these bands based on the same one-off analysis used for Option 2. Furthermore this analysis incorrectly 2009 response costs (£175m) extrapolated using additional costs of £129.6m (combination of response costs, reserve and circuit benefits) rather than the additional response costs of £110.7m. This analysis is therefore inconsistent with Option 2 and is inaccurate and fragile; the development of a charging option on this basis is both arbitrary and unstable.

[4] Future frequency response requirements – National Grid Operational Forum – June 2010
http://www.nationalgrid.com/NR/rdonlyres/3CB70354-DDF3-47F4-9E34-464B651A4761/41762/Future_Freq_Response_Jun10_OpsForum.pdf

Comparison of options

The analysis presented by NG to compare the three options is a limited single scenario based on a number of broad and inaccurate assumptions. The use of a theoretical day with a flat profile is not realistic. Furthermore NG has chosen a scenario which includes one unit of between 700MW and 1500MW and a second unit between 1500MW and 1800MW. NG has further assumed that these large units would have a 100% load factor and has pro-rated the number remaining generators accordingly assuming they are also operating baseload. This scenario does not represent any future contracted generation background nor does it relate to the assumptions used in the SQSS review group's amendment report for large generating units. It is not clear how this scenario has been developed or the rationale for choosing its assumptions.

This single unrealistic scenario does not capture the diversity of possible situations which impact on NG's response (and reserve) requirements on a day to day basis, and therefore does not give generators a robust indication of what their daily charges would be under these proposals.

EDF Energy would have expected a more detailed assessment of the options including some analysis of the impact on market participants (as was provided in GB ECM 13 and GB ECM 18) prior to the recommendation of a targeted option. EDF Energy is looking at a comparison of 2009 costs under these options to understand the materiality for our own generation portfolio, however due to the complexity of this work we have not been able to complete it within the timescales required for our consultation response.

NG's assessment of the options

Prior to stating their initial view to implement Option 2, NG presents their own assessment against their relevant objectives. EDF Energy believes that this assessment is narrow and biased towards their specific interpretation of their objective to "reflect… the costs incurred by transmission licensees" as 'cost-reflective'. NG's entire focus of their assessment is this narrow (and potentially incorrect) interpretation. This becomes the priority and emphasis of their assessment above all their other relevant objectives and statutory duties.

We have provided a number of opposing comments on NG's view that generation size is proportional to risk and therefore cost. NG's reliance on this assumption in their assessment of cost reflectivity means that their assessment is limited.

As has been discussed NG's consideration of Option 1 (current arrangements) does not review historic decisions to recover costs equally from demand and generation. Indeed GSR007 found that the GB power system has historically evolved such that the maximum infeed loss is consistent with the available generation technology. There is a precedent here that the development and revision to infeed loss limits has been associated with

retention of socialised charging. It is clearly inconsistent to suggest that the current proposed increase in infeed loss limits merits a change in the charging approach for frequency response costs.

We are also disappointed that NG does not discuss the consistent industry views (presented in the charging pre-consultation) that targeted costs are discriminatory.

It is also of note that the GSR007 Amendment report stated that by increasing infeed loss limits the three transmission owners, and NG in their role of system operator, would facilitate and promote competition in the generation of electricity as required by their duties under the Electricity Act. Targeting costs onto those very units for which limits would be raised is inconsistent with these duties and does not meet NG's relevant charging objective "to facilitate effective competition in generation and supply".

We are also unclear as to why NG associates the targeted cost approach as being consistent with their requirement to "reflect developments in its transmission business". The SQSS working group (which NG chaired) did not find that the change in infeed loss limits constituted a fundamental change in the requirements of the transmission owners businesses and therefore NG's views seem inconsistent with this finding and potentially irrelevant.

Current and future frequency response provision

NG does not consider the interaction of its proposals to target frequency response costs with the current contracting and market arrangements for providing frequency response. Nor is it acknowledged that there are other industry working groups discussing future arrangements for frequency response[5]. These proposals could cut across that work and have implications for the groups' current thinking.

Implementation

NG indicates an implementation date of 1 April 2012 for their preferred option of targeted costs and acknowledges that there will be consequential changes to information systems, data processes, BSUoS systems as well as associated CUSC changes. The materiality of this should not be underestimated. Industry parties have had very limited opportunity to assess these consequences and determine the impact on their own systems. The scope and costs of any work to implement changes is likely to be significant. All of these issues should be considered holistically prior to any decision being made to target costs. Without this consideration there is no evidence that the significant step change away from existing arrangements is proportional.

[5] Joint Grid Code and BSSG working group established in May 2008
http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/workinggroups/freqresp/

Ofgem should veto a decision to implement Options 2 or 3

EDF Energy continues to support the charging of frequency response through BSUoS to all system users on an equal basis i.e. option 1 - commodity charge.

In view of the numerous and relevant concerns we have with this proposal we feel strongly that Ofgem must use its power of veto to prevent the targeting of frequency response charging once this issue is assessed against their statutory duties.

Appendix 1
EDF Energy analysis of longer term effects

We have utilised our long-term despatch model to quantify the impacts of some of the issues arising in the area of this consultation. Our model is a fundamental model with dynamic operating constraints on plants, with simultaneous least-cost optimisation for supply / demand equilibrium in the energy market and the provision of reserve. We use a Monte-Carlo approach based on historical weather (wind, temperature samples) to simulate the stochastic effects of load, gas price and wind generation. The software is provided commercially by Energy Exemplar, and called Plexos, whilst the data are long-term EDF Energy assumptions for commodity prices, plant mix and technical characteristics, and demand growth. Note that monetary figures are in real 2008 values.

We have used the model to determine the sensitivity of key system parameters to scenarios around the development of new nuclear power stations.

We have a base case, where two EPRs are operating in 2020 with a given set of commodity price assumptions, plant mix etc. In the base case, 2.5 GW of headroom is held on operating plant. (This is held to provide frequency response, but due to the perfect foresight of the model in the short-term optimisation, the response is never required. Hence we model the costs of creating the headroom, but not the costs of despatching it to counter deviations in frequency.)

Case 1: Remove the two EPRs all else remaining constant. Baseload power price increases by 2.4 £/MWh, and load pays an additional £ 1060M. Carbon emissions increase by 13.4 Mt or 10.4 %. These cost additional £ 409M at the assumed market price.

Case 2: Remove the two EPRs and replace with 3.2 GW of new CCGT capacity. Baseload power price is unchanged from base case. Carbon emissions increase by 8.6 Mt or 6.7 %. These cost additional £ 261M at the assumed market price.

Case 3: Remove the two EPRs and replace with 3.2 GW of alternative nuclear capacity, which is assumed not to require an increase in headroom from the present assumption of 2.0 GW. The cost of creating headroom falls from £ 56.7M to £ 38.0M. Note that the cost of reserve is the compensation paid to plants to hold headroom, so that plants are indifferent between providing energy and headroom, and that plants can provide up to 10 % of their maximum capacity as headroom, only whilst they are generating.

We believe it is a reasonable assumption that the cost of utilising reserve, i.e. response costs, will not increase due to the larger unit size; it is the cost of creating additional headroom, i.e. upward reserve costs that are expected to change. This assumption differs from the consultation calculations, which show a linear increase in both costs.

For comparison, when our model is run for 2010, the cost of creating headroom is £ 56.0M. This is very close to the figure provided in the consultation document for the actual incurred cost of reserve provision (£ 55.0 M). The decrease between 2010 and 2020 is most likely due to the closure of the oldest, least efficient plants, which reduces the difference in efficiency between the plant that is marginal for energy and the plant that is marginal for reserve provision.

We draw three conclusions from these studies:

1. A delay in commissioning of new nuclear capacity, which is not filled by conventional technology – perhaps since it will not be economic to construct a new CCGT to take advantage of a delay of only a few years – leads to huge costs in increased power prices and increased carbon emissions.
2. If conventional capacity is constructed instead of new nuclear capacity, there is a significant increase in carbon emissions.
3. The additional cost of creating headroom to accommodate EPRs rather then AP1000 appears to be over-estimated in National Grid's calculations.

EDF Energy
July 2010

Appendix 2
Poyry analysis[6]

Pöyry modelling of impact

Frequency response requirements in BETTA are based on the largest potential infeed loss, adjusted for demand response. In our 2009 multi–client intermittency study for Great Britain and Ireland, Pöyry worked with National Grid – who were a founder member and the key contributor of network related modelling assumptions – to formulate frequency response requirements[7].

Of relevance to this modelling, the maximum infeed parameter was set to 1260MW in the early years of the study, and 1660MW (i.e. an additional 400MW) once the first EPR was assumed to be commissioned (by 2020). These settings were based on specific advice provided by National Grid on the parameters we should use in the GB Intermittency study modelling to be consistent with largest unit sizes of 1320MW and 1800MW respectively[8].

EDF Energy is interested in the cost implications of varying the maximum infeed loss, as they affect the relative economics of generation units above 1320MW compared with those below. EDF Energy asked Pöyry to examine the impact on costs, and also CO_2 emissions, of varying the infeed parameter in our Zephyr model. In this analysis, we have considered the effect of keeping the infeed parameter constant, i.e. not increasing it by 400MW in 2020. This reflects the scenario where new nuclear capacity is provided using AP1000 units rather than the larger EPR units currently assumed to be the basis for new nuclear plant build in the UK.

We have run a revised scenario (with no infeed increase) in Zephyr; and compared the results for total variable costs and CO_2 emissions with the results from our Core scenario in the original 2009 intermittency study. This note presents the output of the modelling for the years 2020 and 2030. We find that the larger frequency response requirement in the Core scenario means that total variable costs are around £37m higher in 2020 rising to £52m by 2030 due to the additional cost of part loading plant.

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6 Extracted 'Review of National Grid charging proposal for largest loss frequency response' a note from Poyry Energy Consulting to EDF Energy 23 July 2010

7 We also formulated a 4–hour reserve requirement, although in our modelling this constraint was non–binding. The cost impact of varying the maximum infeed is therefore limited to the implications for the provision of frequency response in this analysis.

8 This reflects the fact large generating plant have sizeable on–site loads which reduce the net export of power onto the transmission system; and thus in the event of a trip, the transmission system 'sees' the loss of the generation export **not** the full unit capacity.

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23 July, 2010

Dear Adam,

GB ECM-19: Charging for Large Loss Frequency Response

Thank you for the opportunity to respond the above consultation. E.ON UK continues not to support this proposal as it appears not to conform with the non discrimination provisions of National Grid's licence. It is also a significant departure from the present approach whereby response is treated as a common good procured by National Grid on behalf of all Users, who crucially cannot opt for a lower standard of service. This is why up to now its costs have been socialised within BSUoS.

As well as the above concerns we also make a number of points about other aspects of the consultation document.

Discrimination and Cost Reflectivity

Discrimination and cost reflectivity issues go hand in hand. If a service is not provided cost reflectively then there is likely to be a case of undue discrimination.

As you know, paragraph 2 of condition C7 of National Grid's transmission licence prohibits it from discriminating when charging for the provision of particular services identified in its statement of use of system charges:

"..the licensee shall not make charges for provision of use of system to any authorised electricity operator or class or classes of authorised electricity operator which differ in respect of any item separately identified in the statement referred to at paragraph 2(b) of

standard condition C4 (Charges for use of system) from those for provision of similar items under use of system to any other authorised electricity operator or class or classes of authorised electricity operator except in so far as such differences reasonably reflect differences in the costs associated with such provision."

In other words National Grid should only charge different rates for providing a service to a user where the cost of providing that service to that particular customer varies from the cost of providing it to others.

Therefore, consideration needs to be given to the service that National Grid is providing to a particular user when it provides frequency response. Our interpretation is that the service that is provided to a generation User is to hold the frequency within required limits, in the circumstances where demand changes unexpectedly or when another generator's plant trips off the system. In terms of how the cost of the service provided to that User changes with plant size, it is not the size of the particular User which is important, but the size of the other Users on the system. This may be illustrated by the following simplified example.

Imagine a simple system where there are the following 5 generating units on the system:

Generator A = 1000MW
Generator B = 500MW
Generator C = 100MW
Generator D = 1320MW
Generator E = 1800MW

Generator E is clearly the largest plant on the system. However, to provide a frequency within limits to this generator to allow it to continue to generate on a stable system, enough response needs to be held to cover the largest loss from another User which is the 1320MW of Generator D. For the other generators the possibility of Generator E's 1800MW tripping needs to be covered. So whilst the existence of Generator E on the system may drive a requirement for more response to be held, this response is to provide the service to other generators, not Generator E.

It is not possible to make a link between the cost of providing the frequency response service to a particular generator and the size of its own generation unit. Therefore, to charge it for that service on such a basis must be unduly discriminatory and therefore contrary to the provisions of Condition C7.

Additionally, as pointed out in the consultation document, one of National Grid's objectives for the charging methodology is "charging on the basis of services provided". This objective accords with the provisions of Condition C7 above. Conversely, the approach to GBECM-19 is to target generators in accordance with "the risk they represent to the system" rather than reflecting the cost of providing that service to those generators. The concept of "risk to the system" is not one which is contained in Condition C7. It would be helpful to understand its relevance in the context of the provision of the response service to individual generators.

We note that National Grid has concluded that to charge generators differentially dependent on their size improves cost reflectivity of services provided. As we have stated above, we believe that the service provided to generators is to maintain frequency within prescribed ranges should another generator trip from the system or due to demand fluctuations. If our interpretation is deemed incorrect then it is important that the alternative definition of the service is clarified so that users can fully understand the implications of each of the proposed options.

Why have response costs been socialised up to now?

In our response to the pre consultation we explored why it was that response costs have until now been socialised within BSUoS. It is worth reiterating these points as they didn't seem to be addressed in the consultation document.

In order to better understand the reason for why response costs were socialised, we have looked back at Ofgem's views in the documentation it issued at the time BSUoS was devised. There are number of consultation documents and decision documents from that period, but the main documents appear to be from December 1999[1] and April 2000[2]. The consistent point that is made is that the costs in BSUoS are smeared because all users benefit from the services provided.

The December document in particular refers to the principle of sharing balancing costs in BSUoS. For instance on page 36 it states, "*All users of the system benefit from the actions taken by the SO as system balancer to maintain the quality of supplies. There is no correlation between a participant's energy balance position and their dependence on system balancing services. Consequently, as far as possible, the costs of these actions should be recovered from all participants on a fair and non-discriminatory basis*".

Further down this page it states, *"If costs of particular services are targeted at participants, it is important that they have the opportunity to express their views on the value that they place on particular services"*. Furthermore in respect of response it says "*it is realised that there are certain common services, such as frequency response, where the preferences of individual participants cannot readily be taken into account*." These are key quotes as they focus on important principles.

Firstly, the basis for allocating these costs is in part determined by who benefits from the services that are being provided. If all users benefit from the service then this is a reason for all users to pay for them. Secondly, as different users are unable to acquire these services to their own particular preferred standard or to express the value that they place on the service, then this limits the basis for differential charging. That is, due to the interconnected nature of the system, frequency is maintained to a common standard and there is clearly no option for a user to request that the system is operated to a different standard at a lower or greater cost. Therefore, Users are buying a common service with no choice over the quality of service which is provided. This is why a common charge should be made to all Users for this service.

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[1] NGC System Operator Incentives, Transmission Access and Losses Under NETA A Consultation Document: December 1999

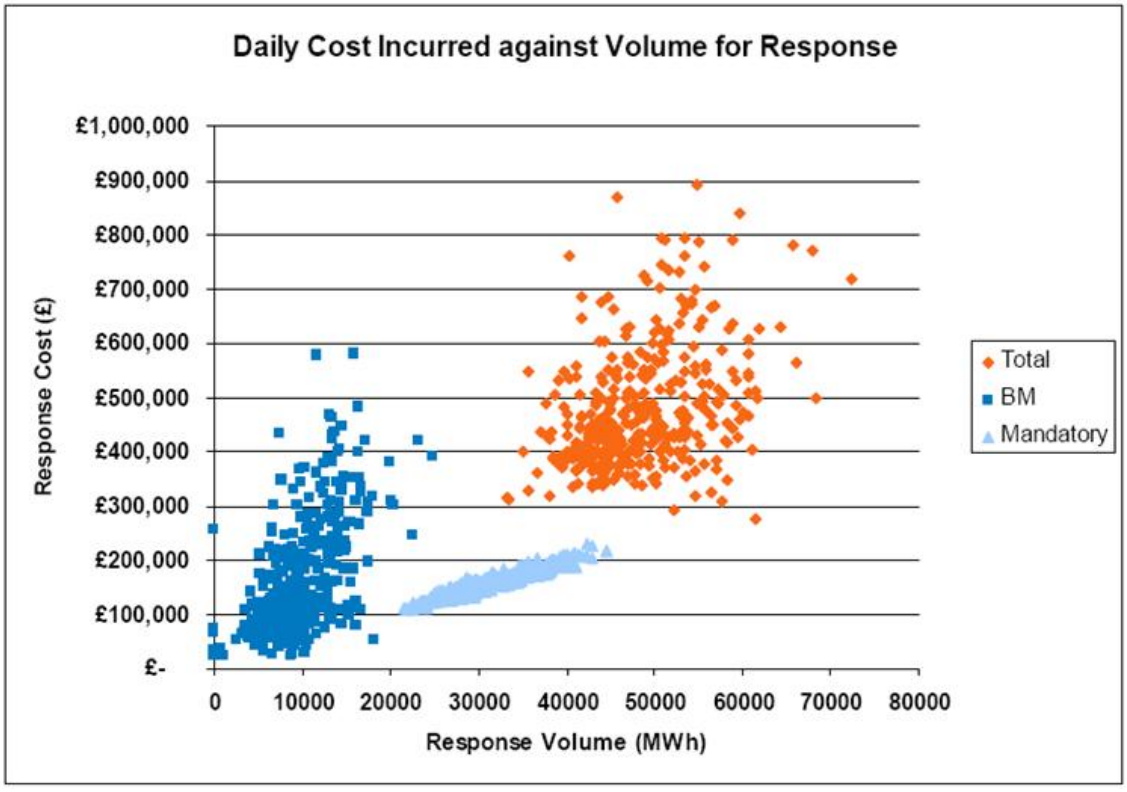
[2] NGC systems operations under NETA: transitional arrangements - A consultation document: April 2000

Other issues

Although we believe that the principle of GBECM-19 is fundamentally flawed as described above, we also have some further comments on elements of the consultation and proposals. Some of our comments relate to the concept of the risk that a generator poses to the system and show that, even if you were to accept this as a valid concept in the context of this charge, the proposals do not seem to address this consistently. Clearly, these comments should not be taken as tacit acceptance of the "risk to the system" argument.

Relationship between the cost of holding response and generator size

Whilst additional response would instinctively be the result of connecting larger units to the network, we are not convinced that the analysis of this relationship has been carried out on the correct basis. We formed this view based on an assumption that is made on page 10 of the document. Page 10 contains the following graph showing the relationship between response cost and volume in 2009.



As can be seen from the graph, there is a strong correlation between the cost of mandatory response and its volume. However, the document goes on to state that it would be, on balance, reasonable to assume a linear relationship between the total cost of response and its volume. Total reserve costs are shown by the red plot on the graph. We do not believe that this shows a linear relationship between the two variables. The assumption that has been made that such a relationship exists therefore cannot be considered as a sound foundation for the subsequent analysis and proposals that follow

later in the document.

The Capacity Charge and Banded Commodity Charge Options

Although in principle we believe that these options are unduly discriminatory, we also have some additional concerns about the specific proposals that have been put forward. The first issue is that we are uncertain as to what the proposed charges are aiming to achieve in terms of user behaviour. This was an issue we raised in response to the pre-consultation document, but our concerns remain.

It would appear that these proposals are not aimed at the original decision to choose the relevant size of generating unit but at subsequent running decisions, as the charges are levied on the basis of whether a generator is running on a particular day. The first question to ask is whether National Grid's response requirements per day are tailored to reflect the running decisions of generators in this manner? Clearly, if they are not then the purpose of charging in this manner is questionable. If so, the second question is whether it is the maximum capacity of the unit which is operating which is important, or the level at which it will be operating? It is not possible to infer this from the charges themselves as both methods appear to be based primarily on the capacity of the generator, but then are scaled in some manner to reflect actual output.

The Banded Commodity Charge is applied to all generators in the relevant capacity band size on an equal basis. Therefore, a 500MW generator operating at 250MW is treated in the same manner as one operating at full output although the trip risk is not the same. Clearly the first generator would, through the commoditised nature of the charge, be exposed to half of the total cost of the second generator. However, it would have a charge significantly different in size to a generator of 250MW capacity which is operating at full output and poses a similar risk.

On a related note we would question whether generators up to 300MW should attract no charge at all. We note the comment in 5.8 that National Grid considers that generators below 350MW do not pose an "additional risk to the system" over and above the response held for dynamic fluctuations in frequency. This does not seem to be the same as saying that no response is held for these smaller generation sizes. For instance, should a 250MW generator trip from the system, is it correct to assume that no response services would be used to bring it back into balance? The Banded Commodity Charge appears to be recovering the total response cost incurred, not just the additional cost above the minimum.

The Capacity Charge at first appears to be based on the full capacity of the generator connected on the day. However, the worked example in the spreadsheet provided shows that it will be applied on a proportion of a generator's output. For example, a generator of 600MW operating at 40% of output is charged at 40% of the cost of a full 600MW generator when it is effectively posing the same risk as a 240MW generator which would attract a cost of zero.

We believe that it is the actual output of the generator which represents the size of the trip risk (as well as the reliability of the generator which is ignored in these proposals and is

arguably more significant). However, both proposals appear to treat equal trip risks unequally. Therefore, even if one were to accept the “risk to the system” approach to allocating the cost of the response service, these proposals would still appear to be unduly discriminatory.

The cost benefit analysis

In the document a cost benefit analysis is undertaken to understand the net cost associated with connecting larger generation units to the network. In this analysis, the net cost of a single baseload 1800MW is calculated to be £129.6m. This figure is made up of cost/benefit elements of Response, Reserve and System Design. We are keen to understand the exact purpose of the analysis. Will the intention be to charge generators on this net basis? If so how will TNUoS be adjusted to reflect the reduction in System Design Costs which are credited to the generators concerned through this charge rather than being socialised in the total allowed revenue?

I hope the above comments prove helpful. As you can see, we have fundamental concerns about the GB ECM-19 proposals and believe that response costs should continue to be recovered through BSUoS as present.

Yours sincerely

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23rd July 2010

Dear Adam,

Re: Charging for Large Loss Frequency Response

Fred.Olsen has been involved in wind power since the mid 90's with presence in Norway, Sweden, UK, Ireland and Canada. Fred Olsen Renewables Limited (FORL) has 316MW of operational wind projects, a further 135MW consented in the UK and a further 1.1GW consented in the Irish Sea. This makes FORL a significant independent generator in the wind energy sector. In addition, FORL are BWEA, SRF, IWEA and NOW Ireland members and are active on a number of the industry groups and FORL staff have, and continue to be, involved with numerous industry working groups such as RAB Grid Group.
As FORL have contributed to the RenewableUK response this is largely a duplicate of that response.

Overview:

The historical lack of cost reflectivity within current charging methodologies, for recovering costs associated with Large Loss Frequency Response, has been highlighted by recent National Grid analysis, especially regarding the potential treatment of new generation plants possessing installed capacity in excess of the current 1320kW infrequent loss limit. As stated by National Grid within the consultation, continuing with the existing commodity regime does not adequately account for cost inequalities between smaller and larger generators, and their respective risks and potential system impacts regarding associate loss of power infeed.

By increasing normal loss limits from 1000kW to 1320kW, and by increasing infrequent loss limits from 1320kW to 1800kW, related charging methodologies would enable the connection of larger generator units (or larger groups) in future. The consultations highlights the acceptance of such large units within charging arrangements could increase the annual operational cost to the System Operator by approximately 100%, from £160m to £319m. Under current commodity regime the connection of larger generators would deliver significantly increased charges to existing or new small generating units (e.g. of less than 350MW) which are

acknowledged by National Grid to effectively pose "no additional risk to the system".

National Grid proposes within the consultation three charging options for handling increased loss limits, and we welcome the opportunity to pass comment.

Specifics:

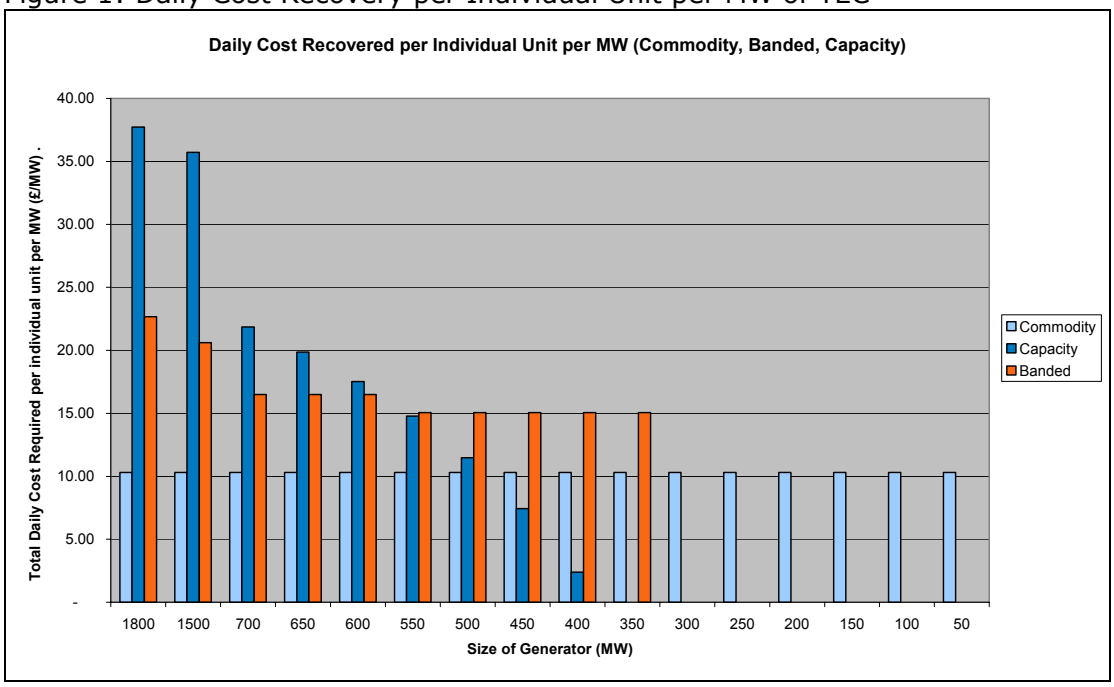
1. We support the use of an ex-post process within this consultation, as opposed to the use of an ex-ante process;

2. Unfortunately National Grid has misunderstood the RenewableUK pre consultation response in their summary of responses. ReUK did not say that charging on the basis of size is discriminatory. Quite the reverse. Current charging is discriminatory in that wind generators with vary small unit sizes (currently <4MW) have no impact on spinning reserve when they trip and yet are charged on the same basis as large generators which have a large cost impact

3. We agree with the proposal that generators on spurs should not be charged on the basis of spur risk as this risk is under the transmission owner's and system operator's control.

4. We are mindful that the current charging regime, and all alternative options proposed within this consultation, partially interprets the risk associated with each generating plant on the basis of a plant's TEC, rather than its peak or average MW output over any set period. Following on from such an approach RenewableUK has processed the data made available by National Grid within their Clarification Note to calculate the charging cost per MW of TEC, as per the scenarios stated within the consultation. We feel the data comparison contained within Figure 1 below better illustrates the issue of cost reflectivity, than consideration of a generation unit based comparison, as per Figure 11 within the consultation.

Figure 1: Daily Cost Recovery per Individual Unit per MW of TEC



5. Figure 1 shows the commodity regime to uniformly levelise charging across all generation sizes, regardless of the risk posed to system operation by different generation size. In our view this regime unacceptably discriminates against smaller generators, and does not uphold the principle of cost reflectivity.

6. Figure 1 shows the proposed banded regime to offer partial cost reflectivity in that sub 300MW generators are allocated a banding term of zero, in line with the affirmation that such generators pose no additional risk to system operation. We maintain that an insufficient reflection of cost is absorbed within this regime for generators possessing a TEC upwards of 300MW. For example, within the scenario provide by National Grid, the daily recovered cost for a 1800MW generation unit per kW of TEC is calculated to be 50% higher than that imposed upon a 350MW unit, or 37% higher than imposed upon a 700MW unit, despite raised loss limits contributing to a ~100% increase in annual operational costs to accommodate larger generation units.

7. We understand from RenewableUK after a discussion with National Grid that the consultation proposes a move away from current practice whereby cost recovery directly links to metered HH output, towards cost recovery directly linking to forecast output (as submitted at Final Physical Notification). We recognise that such an approach would more accurately link costs to the forecast risks on which response is calculated. However we note the variance that may result between FPN and actual output, particularly for variable renewable generators. Such variance will depend upon the accuracy of applied forecasting methodologies and the length of the forecast (i.e. how far in advance of the associate HH is the forecast conducted). We recommend such variance is unlikely to be significant but could affect the extent to which the contracted response exceeds, or is less than, the ideal levels of response required for regulatory compliance. Optimising cost efficiency will depend on accurate and regular forecasting carried as close to real time as practicably possible.

8. We recommend that the proposed capacity regime is the optimum solution from those proposed by National Grid, and that this solution is progressed for adoption and implementation.

9. We have no comment to make on the potential savings that may or may not be captured in association with the reduction of circuits required regarding the connection of larger generation units within newly proposed charging regimes.

10. With the development of smart grids we would expect more options to provide "spinning reserve" e.g. from demand management. However, resources which are delivering a spinning reserve service will not be available to provide other longer timescale reserve services. It would therefore be difficult to predict how these new technologies might affect the costs of spinning reserve, however we recommend National Grid recognise demand management technologies at the appropriate time.

11. We maintain that wind turbines are relatively small generators, typically less than circa 3MW in rating. The impact of the simultaneous trip of one, two or even several of these generating units will have no impact on the spinning reserve requirements. There are no scenarios where a common mode failure would cause simultaneous tripping, except in failure of a

single non-redundant element of the electrical collection or grid connection. These elements akin to transmission circuits in reliability terms and therefore should be excluded from the assessment. In any case they will rarely if ever result in a trip of over 350MW. Therefore, in a cost reflective system, wind turbines should not be liable for any spinning reserve costs, unless they are amalgamated into groupings of over 300-350MW1, and connected by a single electrical element, and therefore vulnerable to an instantaneous loss of 300-350MW or more. Given design decisions that will be taken shortly for larger windfarms it is vital that the treatment of these projects is set and fixed so that cost effective design decisions can be taken as these will endure for the next 25 years or so.

In conclusion, FORL recommends the proposed capacity charging regime for progression and implementation.

If you have any further questions, please do not hesitate to get in touch.

Yours sincerely,

Graeme Cooper
Policy, Regulatory and Compliance Manager
Fred.Olsen Renewables Ltd.

Adam Sims
Regulatory Frameworks, Floor B3
Transmission Commercial
National Grid House
Warwick Technology Park
Gallows Hill Warwick
CV34 6DA

23rd July 2010

Dear Adam,

Consultation GB ECM-19 Charging for Large Loss Frequency Response

InterGen welcomes the opportunity to respond to the above consultation. InterGen is the UK's most successful new entrant independent generator, operating over 2.5GW of efficient gas-fired plant in the UK with an additional 1.8GW in development. Our response to this consultation is set out in light of our experience of the UK market over the last 15 years.

It has been estimated that the UK will need to attract £200 billion of investment in the next ten years in order to meet renewable energy targets and maintain security of supply. To this end, the Department of Energy and Climate Change (DECC) decided in 2009 to adopt a 'Connect and Manage' model for long term grid access connections in order to provide new development projects reasonable connection dates, and by agreeing to socialise all associated costs. DECC's remit was to implement a regime that would provide the right environment for investment in order that renewable targets and security of supply concerns were addressed in a timely manner with minimal impact on consumers. InterGen urges National Grid to consider these criteria when determining on charging methodology.

Normal and infrequent loss limits were determined some 20 years ago, to connect a new, large nuclear plant. At that time, the cost of recovering reserve was socialised fully across all users of the network as it was deemed that this was a necessary expense that is incurred in operating a safe and reliable transmission network. InterGen is keen to stress that the GB ECM-19 consultation is not just a new nuclear charging issue, but has implications for large CCGT developments and offshore wind, both generation types essential as the UK moves towards a low carbon future. It is proposed

(GSR007) that there should be an increase to an Infeed Loss Limit of 1800MW from the time it is first needed by a single large unit power station (assumed to be circa 2018). InterGen fully supports early implementation of the proposed increase in order to facilitate the early connection of large generation clusters (such as offshore wind) and smaller generation on constrained spurs, thereby avoiding the need for many miles of new overhead line and the associated environmental and consenting risks.

Securing transmission access, with its lengthy and difficult consultations, is seen as one of the biggest risks for a generation project. Management of project risks is a key concern for developers looking to invest in the UK. Targeted response costs, such as the proposed Capacity Charge and Banded Commodity Charge, will be high and difficult to predict, and will add significant risk to individual development projects. This cost uncertainty is a significant disincentive on developers (and banks) to build large units at a time when new plant is required to alleviate security of supply concerns and to meet 2020 renewable energy targets. The full socialisation of associated costs under DECC's 'Connect and Manage' regime was widely promoted by industry as key in securing the levels of investment needed in new generation, as it reduces the risk to developers. Targeting of Large Loss Frequency Response costs is at odds with this. The principle of Large Loss Frequency Response charging should be consistent with 'Connect and Manage', thereby sending the right signals to the market, investors and developers.

InterGen believes that charging for Large Loss Frequency Response should be fully socialised, regardless of unit size and generation type, and therefore support the adoption of the status quo commodity charge for all generators in the UK.

InterGen would be happy to discuss further any of the issues raised in this response.

Yours Sincerely,

Melissa McKerrow
Head of Public Affairs and Regulation

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Deeside
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First Hydro Company is part of a joint venture between International Power plc and Mitsui & Co., Ltd.

Adam Sims
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National Grid Electricity Transmission Ltd
National Grid House
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Gallows Hill
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CV34 6DA

23th July 2010

Adam.sims@uk.ngrid.com

Dear Adam

GB ECM-19 Charging for Large Loss Frequency Response

International Power (IPR) is responding to your consultation on behalf of First Hydro Company, Saltend Cogeneration Company Ltd, Rugeley Power Ltd, Deeside Power Ltd. and Indian Queens Power Ltd.

The infrequent loss limit is currently set in the SQSS at 1320 MW. This is likely to increase to 1800 MW to allow for an increased size of new BM units. A secondary benefit of the increase would be to allow spur connected double circuits to be rated at up to 1800 MW.

The consultation indicates that the cost of provide frequency response is likely to increase from £100m to £320m per year when this increase to the limit is implemented. We understand that this cost estimate was based on being delivered from dynamic (synchronised) sources. In practice some of the increase in frequency response would be met from LF triggered response which would reduce the cost. We believe that a more thorough review of the cost of providing the increase in response services is required to establish the likely range of costs.

We believe that running the system with an increased infrequent loss limit is likely to benefit many users of the system. Any generation sited on a double circuit (either as a spur or post trip/planned outage of a parallel circuit) is likely to benefit with additional capacity being available on the circuit.

We believe that the costs in increased frequency response requirements are therefore outweighed by the efficiencies associated with the optimal use of the transmission system and the facility to accommodate larger units.

We support the status quo of commoditised charging via BSUoS for frequency response and do not support the use of a capacity charge or a banded commodity charge. Both of these will discourage larger users from optimal use of the transmission system and lead to larger overall cost for consumers.

In summary, given that the cost of holding additional response is likely to be smaller than that indicated and that the benefits are shared by many users of the system we believe that the current charging arrangements remain equitable and appropriate.

We hope that you find these comments useful

Yours sincerely,

Simon Lord,

Transmission Services Manager

Sims, Adam

From: david.m.ward@magnoxnorthsites.com
Sent: 21 July 2010 17:59
To: Sims, Adam
Subject: Response to ECM-19 Consultation

To Adam Sims, National Grid

By email to: Adam.Sims@uk.ngrid.com

Adam

Consultation GB ECM-19
"Charging for Large Loss Frequency Response",

This email is the response of Magnox North Ltd to the above consultation. Magnox North currently operates two large power stations, one small embedded power station, and several former power station sites, which are now directly-connected demand sites.

We did not respond to the pre-consultation on this modification proposal, but note that 11 other organisations did respond. It is notable that the overwhelming majority of respondents expressed the view that charging generators for frequency response based on size is undesirable as it is discriminatory and creates investment uncertainty, and that the present arrangement of socialisation of the costs should be retained. This is also our view. It will be difficult for generating companies, particularly smaller generating companies, to forecast their liability under this proposed charging methodology. Also, existing generators will not be able to respond to the price signals from the banded charging, so it does not provide an economic benefit.

The costs of frequency response and voltage control have been socialised since the industry was privatised in 1990. This was based on the recognition that all users benefit from well-controlled frequency and voltage. The only change has been to spread the charging base from demand only under the Pool, to both generation and demand following the introduction of NETA in 2001. This charging arrangement is simple to administer, and avoids any arbitrary decisions on how much each party contributes to the costs. It is not clear why National Grid suddenly thinks the principal should be changed substantially for frequency response after 20 years. The proposed increase in the "Infrequent infeed loss limit" from 1320MW to 1800MW is not an exceptional change when compared to the growth in demand. The "infrequent infeed loss limit" has effectively been set at 1320 MW since 1975 (see CEGB Planning Memorandum PLM-SP-1, Issue 1, dated September 1975). Since that time, the average system demand has increased by around 60%, whereas the suggested increase from 1320MW to 1800 MW is only a 36% increase. Hence, even after the proposed increase in infeed loss limit, it will still be a smaller fraction of average system demand than it was in 1975. It is likely that system demand will grow further before the first 1800MW plant will be ready to connect.

The benefits to the system of increasing the infeed loss limits have been underestimated. Not only would it allow a reduced number of connecting circuits to some new generation, it would more importantly allow significant increases in generation in certain locations without triggering the need for any additional circuits. Certainly the CEGB, and latterly National Grid, has used the current limit (1320MW) to maximise the generation that can be installed in certain locations. This was acknowledged as long ago as 1994, in the review of transmission security standards published that year. We note that the "Vision 2020" document published by ENSG, which National Grid helped to write, assumes the benefit of the 1800MW limit in future.

The argument presented in this consultation is that charges should be based on the perceived cost that individual parties are deemed to cause. The problem with this is there are other factors that could also be argued to affect the cost that an individual generating unit causes. For example

- The proposed new nuclear units are likely to have a much larger inertia constant than most existing generators, which would increase the overall inertia of the system, and hence assist frequency control. It could be argued that this would tend to reduce the costs, and should be reflected in lower charges.
- By the same argument, large wind turbines currently contribute little or no inertia to the system, so making frequency control harder. One could argue that they should pay higher charges.
- The continued increase in the number of wind turbines on the system is likely to require an increase in the amount of reserve carried. One could argue that wind turbines should pay higher charges for this.

Overall the present arrangement is simpler, and avoids such arguments.

We have some specific comments on particular points in the consultation document:

- Section 5.2.1 states that "nuclear generation is unsuited to shutting down over trough periods". The important issue is whether nuclear units can readily cycle between full load and low load, not necessarily whether they can "shut down". While it is true that our Magnox reactor units cannot routinely load-cycle in this way, it is not true of new designs. Both the reactor designs currently being assessed by the nuclear regulator are able to cycle between full load and 25% load on a daily basis.
- Section 5.8 states that the instantaneous trip frequency of transmission spurs is much lower than the trip frequency of large generators. This does not correspond with our experience. In its 39 year operating life so far, the trip frequency of the transmission connections to our Wylfa power station has been greater than 0.35 per year. Bradwell power station, now closed, experienced a similar trip rate during its operating life. By contrast our records for the last 18 years at Wylfa indicate only 0.31 instantaneous trips per reactor per year. The world average for all nuclear units is around 0.5 per reactor per year.
- In section 5.8.3 on banded commodity charge it suggests banding using TEC. This is inconsistent with the argument in the consultation document that costs are mainly driven by the size of unit that can be tripped. This is because TEC is a station quantity, not a unit quantity. To be consistent the banding if used would need to be based on generating unit size, or boiler/reactor size if a boiler feeds more than one generating unit.

These comments are not confidential. I am happy to respond to any questions on them

David Ward

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---------- End of message

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Date: 23/07/2010

Adam Sims
Regulatory frameworks, Floor B3,
Transmission Commercial,
National Grid House, Warwick Technology Park,
Gallows Hills, Warwick, CV34 6DA

Dear Adam,

Charging for Large Loss Frequency Response

RenewableUK (formerly the British Wind Energy Association (BWEA)) is the trade and professional body for the UK wind and marine renewables industries. Formed in 1978, and with over 600 corporate members, RenewableUK is the leading renewable energy trade association in the UK, representing the large majority of the UK's wind, wave, and tidal energy companies.

Overview:

The historical lack of cost reflectivity within current charging methodologies, for recovering costs associated with Large Loss Frequency Response, has been highlighted by recent National Grid analysis, especially regarding the potential treatment of new generation plants possessing installed capacity in excess of the current 1320kW infrequent loss limit. As stated by National Grid within the consultation, **continuing with the existing commodity regime does not adequately account for cost inequalities between smaller and larger generators**, and their respective risks and potential system impacts regarding associate loss of power infeed.

By increasing normal loss limits from 1000kW to 1320kW, and by increasing infrequent loss limits from 1320kW to 1800kW, related charging methodologies would enable the connection of larger generator units (or larger groups) in future. The consultations highlights the acceptance of such large units within charging arrangements could increase the annual operational cost to the System Operator by approximately 100%, from £160m to £319m. Under current commodity regime the connection of larger generators would deliver significantly increased charges to existing or new small generating units (e.g. of less than 350MW) which are acknowledged by National Grid to effectively pose “no additional risk to the system”.

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Specifics:

1. We support the use of an ex-post process within this consultation, as opposed to the use of an ex-ante process;

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4. We are mindful that the current charging regime, and all alternative options proposed within this consultation, partially interprets the risk associated with each generating plant on the basis of a plant's TEC, rather than its peak or average MW output over any set period. Following on from such an approach RenewableUK has processed the data made available by National Grid within their Clarification Note to calculate the charging cost per MW of TEC, as per the scenarios stated within the consultation. We feel the data comparison contained within Figure 1 below better illustrates the issue of cost reflectivity, than consideration of a generation unit based comparison, as per Figure 11 within the consultation.

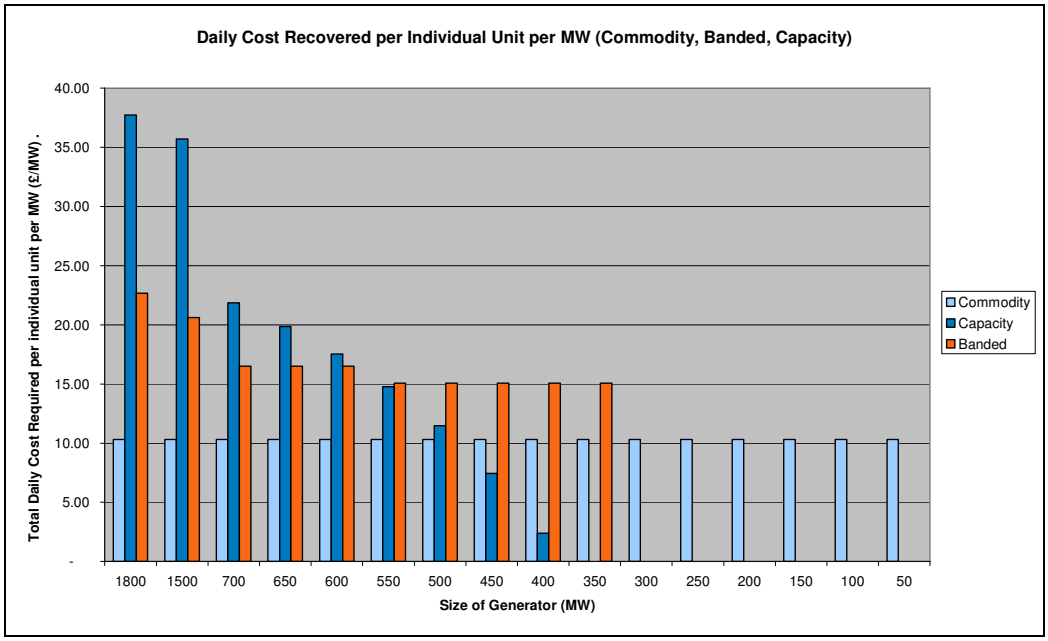

Figure 1: Daily Cost Recovery per Individual Unit per MW of TEC

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6. Figure 1 shows the proposed banded regime to offer partial cost reflectivity in that sub 300MW generators are allocated a banding term of zero, in line with the affirmation that such generators pose no additional risk to system operation. We maintain that an insufficient reflection of cost is absorbed within this regime for generators possessing a TEC upwards of 300MW. For example, within the scenario provide by National Grid, the daily recovered cost for a 1800MW generation unit per kW of TEC is calculated to be 50% higher than that imposed upon a 350MW unit, or 37% higher than imposed upon a 700MW unit, despite raised loss limits contributing to a ~100% increase in annual operational costs to accommodate larger generation units.

7. RenewableUK understands from discussion with National Grid that the consultation proposes a move away from current practice whereby cost recovery directly links to metered HH output, towards cost recovery directly linking to forecast output (as submitted at Final Physical Notification). We recognise that such an approach would more accurately link costs to the forecast risks on which response is calculated. However we note the variance that may result between FPN and actual output, particularly for variable renewable generators. Such variance will depend upon the accuracy of applied forecasting methodologies and the length of the forecast (i.e. how far in advance of the associate HH is the forecast conducted). We recommend such variance is unlikely to be significant but could affect the extent to which the contracted response exceeds, or is less than, the ideal levels of response required for regulatory compliance. Optimising cost efficiency will depend on accurate and regular forecasting carried as close to real time as practicably possible.

8. We recommend that the proposed capacity regime is the optimum solution from those proposed by National Grid, and that this solution is progressed for adoption and implementation.

9. We have no comment to make on the potential savings that may or may not be captured in association with the reduction of circuits required regarding the connection of larger generation units within newly proposed charging regimes.

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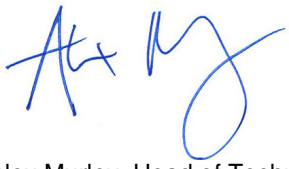
services. It would therefore be difficult to predict how these new technologies might affect the costs of spinning reserve, however we recommend National Grid recognise demand management technologies at the appropriate time.

11. We maintain that wind turbines are relatively small generators, typically less than circa 3MW in rating. The impact of the simultaneous trip of one, two or even several of these generating units will have no impact on the spinning reserve requirements. There are no scenarios where a common mode failure would cause simultaneous tripping, except in failure of a single non-redundant element of the electrical collection or grid connection. These elements akin to transmission circuits in reliability terms and therefore should be excluded from the assessment. In any case they will rarely if ever result in a trip of over 350MW. Therefore, in a cost reflective system, wind turbines should not be liable for any spinning reserve costs, unless they are amalgamated into groupings of over 300-350MW[1], and connected by a single electrical element, and therefore vulnerable to an instantaneous loss of 300-350MW or more. Given design decisions that will be taken shortly for larger windfarms it is vital that the treatment of these projects is set and fixed so that cost effective design decisions can be taken as these will endure for the next 25 years or so.

In conclusion, **RenewableUK recommends the proposed capacity charging regime for progression and implementation**.

Yours sincerely,
(by email)



Alex Murley, Head of Technical Affairs for RenewableUK

RWE Supply & Trading

RWE
The energy to lead

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Contact Bill Reed
Phone Phone 01793 893835
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Swindon, July 23rd 2010

Email: adam.sims@uk.ngrid.com

Consultation GB ECM-19 – Charging for Large Loss Frequency Response

Dear Adam,

Thank you for the opportunity to comment on the consultation document entitled "Charging for Large Loss Frequency Response" (GB ECM-19). This response is provided on behalf of the RWE group of companies, including RWE Npower plc, RWE Supply and Trading GmbH and RWE Npower Renewables Limited, a fully owned subsidiary of RWE Innogy GmbH.

The consultation document raises important issues with regard to the charges associated with the provision of a large loss frequency response service. We believe that appropriate incentives are required for all users connecting to the transmission system so that the transmission system is operated in an economic and efficient manner. This means that certain costs may be targeted on users where specific incremental balancing services are required.

In the case of charging for large loss frequency response, we note that the costs are currently socialised across all users. Any proposal to change these arrangements would have a significant impact on both existing generators and those seeking to connect large generating units to the transmission system. We believe that in developing such a change a detailed cost benefit analysis is required. In particular consideration is required as to the effect that such a proposal will have on the costs associated with large generating units that operate at base load, both in terms of the investment signals and the ongoing operating costs. The economies of scale of large generating units, security of supply and low carbon benefits should be considered in such an analysis.

In terms of the proposed changes the commodity charge approach for the specific costs represents the minimum impact in terms of market changes. This remains our preferred approach at this time.

We have a number of observations on the consultation document and associated proposals, and these are considered in the following sections.

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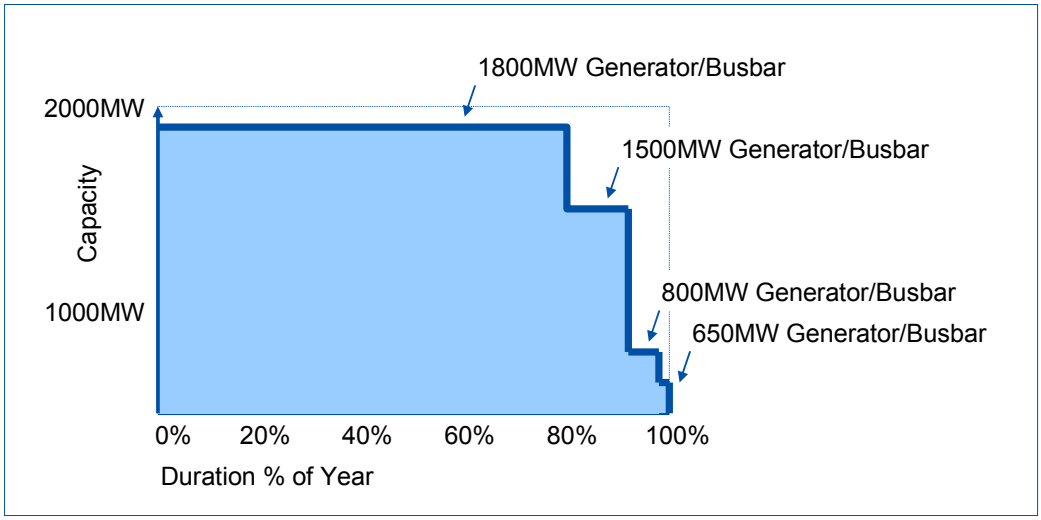
Response Costs attributable to Transmission Connection design
We note from the consultation document that the increase in the NETSSQSS largest infeed loss may enable three 500MW generators to be connected to a single busbar under the new arrangements. Consequently the increased risk of a largest infeed loss will be associated with the configuration of the transmission connection. Therefore, it would appear a perverse outcome to target the costs of frequency response holding onto the generators that are connected under these conditions.

It would be useful to understand what the effect of increasing the normal and infrequent loss limits would have been on the transmission system incident which occurred on the 27th May 2008. In this incident, a loss of 1528MW of generation and the automatic disconnection of 581MW of demand occurred within three minutes. If the increased resilience of the transmission system would have prevented this loss of demand, then this wider system benefit should also be recognised.

Largest Infeed Loss Duration Curve
We believe that it would be informative if National Grid could consider the "largest infeed loss" duration curve in developing its proposals and considering the cost reflectivity of the proposals. Figure 1 implies that the marginal cost of frequency response will always be associated with the costs of meeting the largest infeed loss. It is possible that the connection of larger generating units, changes to connection configurations and increased connection of wind farms will result in generators that form the largest infeed risk differing from time to time. Nevertheless the generator representing the largest infeed loss will always represent the limiting factor.

Figure 1: Illustrative "Largest Infeed Loss" Duration Curve



"Cost Reflective" Charging
It would appear logical from Figure 1 that a fully "cost reflective" marginal charge should aim to target the costs from the largest generator or busbar that is causing the largest infeed loss risk. On this basis, a small number of parties could be exposed to a significant proportion of the frequency response costs. While this would recover the costs and could be considered cost reflective, it would also negate the economies of scale for such units and could result in perverse outcomes in terms of unit size ratings or efficient operation with a consequent effect on security of supply and CO2 emissions.

Rationale for Capacity Charges
The simple capacity charge approach illustrated in the consultation document implies that the charging base for the proposed frequency response charge should be generators larger than 400MW connected to the transmission system while the charging base for the banded capacity proposals would be a certain subset of generators. We do not understand the rationale for the change to the charging base and indeed we believe that such an approach may be discriminatory in its application. We note in particular that since it is the largest infeed loss that must be secured it appears inappropriate to recover costs across generators that "do not pose any additional loss risk to the system". This is similar to the conclusion reached for generators below 350MW (paragraph 5.8).

Banding
The banded capacity charge is an attempt to adjust the charging base in a different way to that implied in the simple capacity charge using what appear to be arbitrary factors in apportioning the costs. We do not support this approach since we do not believe that the discrimination implied can be justified.

Cost recovery and market signals
While it may be considered to be appropriate to recover the incremental costs associated with the frequency response from the party causing the largest infeed loss risk, we do not believe that this would result in an efficient outcome in relation to the charging objectives. We are concerned that users cannot respond to the signals created by the approach under consideration. There is no opportunity to mitigate the risk by for example hedging the costs, and the attribution of certain generators to the charging base appears arbitrary under the capacity charge approach. We do not believe therefore that a case has been made for the introduction on any specific capacity-based charge for the largest infeed loss.

Summary
We believe that considerable additional work is required to justify moving away from the current commoditised basis for recovering the frequency response costs associated with the risk of the loss of the largest infeed. A cost benefit analysis should identify the potential impact of each of the proposals and consider the nature of the charge, the marginal cost, the risk factors, the charging base and the risk management options. On the basis of the proposals presented in GB ECM-19 we do not believe that it has been demonstrated that the proposals will better meet the charging objectives.

If you wish to discuss any aspect of our response, please do not hesitate to contact me.

Yours sincerely

By email

Bill Reed
Market Development Manager
RWE Supply & Trading GmbH

SCOTTISHPOWER
Energy Wholesale

Adam Sims
Transmission Commercial
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

25 June 2010

Dear Adam,

GB ECM-19 Consultation Document
Charging for Large Loss Frequency Response

Thank you for the opportunity to respond to this Consultation Document. This response is submitted on behalf of ScottishPower Energy Management Ltd, ScottishPower Generation Ltd and ScottishPower Renewable Energy Ltd.

ScottishPower believes that the current charging arrangements remain appropriate in the event that the normal and infrequent loss limits are increased as recommended by the SQSS Review Group to facilitate the connection of larger generation units.

Maintenance of system security through the procurement of frequency response is essentially for the public good, with wide societal benefits. Accordingly, and to avoid distorting the market, the costs associated with delivering the benefits of a secure transmission system, should be shared equitably across all energy consumers. We believe that this remains the right approach, both in principle and in practice.

Socialisation of any incremental costs would not require any change to the existing method of cost recovery and would avoid the arbitrary and subjective banding implicit in the alternative charging methodologies.

In order for users to make informed economic decisions on investment and pricing, the size of any targeted reserve cost would need to be known in advance. National Grid has acknowledged the difficulty in forecasting costs through its annual System Operator Incentive Scheme and therefore the accuracy of any ex-ante estimate of reserve costs is likely to be subject to subsequent reconciliation leading to inefficient economic decisions.

Our detailed responses to the questions raised in the consultation document are attached.

I hope you find these comments useful. Should you have any queries on the points raised, please feel free to contact us.

Yours sincerely,

James Anderson
Commercial and Regulation Manager

SCOTTISHPOWER
Energy Wholesale

Responses to the Pre-Consultation

5.3 Benefit of Reduction in Circuits

We are unable to express a view on the appropriateness of the potential annual saving from a reduction in the number of circuits required but would suggest that a sample of more than two circuits would be required to derive an accurate figure. The charging methodology would also need to specify whether this discount would be inflated on an annual basis and when a full review of the discount would be carried out e.g. at the start of each price control period.

5.8 Charging Options

National Grid state in the consultation document that a minimum response requirement of 350MW is maintained to cover dynamic frequency response. As the volume of intermittent generation on the system increases, it could be assumed that this minimum requirement will increase correspondingly and National Grid should explain how often they intend to re-visit the de-miminus charging level.

ScottishPower believes that generators on a single spur should not be forced to bear the costs of any larger risk arising from a change to the normal and infrequent loss limits.

5.8.1 Commodity Charge

ScottishPower believes that commoditisation (MWh) is the most equitable way of allocating response costs as it reflects both the level of generation (MW) at any point in time together with the duration of time (hours) that the generator is running.

5.8.3 Banded Commodity Charge

The mathematical relationship between the cost of response and the risk size derived from 2009 data should be tested against a number of years to ensure consistency. If introduced, how often would National Grid propose to test this relationship to ensure that it remained a valid basis of charging?

6.1 Assessment Against the Relevant Objectives

Facilitating Competition

A commodity charge does not affect the relative competitive position of any individual generator as all generators pay on the same basis. This reflects the benefits accruing to both generation and demand from operating on a secure transmission system.

Users can only decide on the type of technology and size of generating unit at the time of making their initial investment. Existing generators would be unable to respond to any retrospective application of a response unless by closing plant.

An ex-ante charge based on actual running may signal to large generating units to run part-loaded with consequences for thermal efficiency, carbon emissions and market prices.

Users making prospective generation investment decisions require certainty about charges. National Grid have acknowledged their difficulty in accurately forecasting response charges and have therefore proposed an ex-post charge - which provides no certainty to potential investors. National Grid's proposal could be detrimental to achieving the scale of generation investment required to ensure security of supply.

6.2 Implementation

ScottishPower would wish to implement robust systems for the validation of any response charges and would need to develop accurate forecasting models to ensure accurate pricing of electricity products. We envisage that there could be significant costs involved in these systems developments. The proposed change to the SQSS does not come into effect until a unit larger than the current limits is connected to the transmission system. Should a response charge be introduced, it should be timed to coincide with the connection of such a large generation unit with at least 2 years notice to the industry to allow for the costs to be factored into electricity products.

Sims, Adam

From: garth.graham@sse.com

Sent: 23 July 2010 17:34

To: Sims, Adam

Subject: Re: ECM19 - Charging for Large Loss Frequency Response - Notice of Clarification and deadline extension

Dear Adam,

Thank you for your email of 11th June 2010 with the ECM-19 Consultation Document and your email of 5th July 2010 with the Clarification Note.

We have reviewed the consultation document and clarification note.

In addition to this we are mindful that nine of the eleven responses to the earlier pre-consultation (as noted in section 4 of the consultation document and summarised in table 1) believe that continued socilaisation (of the additional cost of holding additional levels of response) is the most appropriate way forward.

We agree with this, not only in terms of avoiding undue discrimination between classes of generators (based purely on an arbitrary size - be that less than 350MW or greater that 1,320MW) but also in terms of the investment uncertainty that could arise otherwise.

We note the comments in section 5.2 of the consultation document in terms of the holding of primary response. We wish to place on record our concern that, over the medium to long term, the decline in flexible plant operating on the system at any given time is likely to increase the risk that primary response will be unavailable on the day. We are mindful, for example, that on a windy summer Sunday morning; in the latter half of this decade and beyond; there might be little, if any, flexible plant operating at that time, thus impeding the primary frequency response capability in GB. This implies that at such times such flexible plant may need to be brought on, even though, from a BM price perspective there are lower cost (but far less flexible, in frequency response terms) plant available.

Furthermore, we are mindful of the arguments made by others to the earlier pre-consultation which noted that the provision on frequency response is required to maintain electricity supplies for end consumers. Given this, others have suggested it may not be appropriate to apply the costs (of frequency response) onto generators. We believe that National Grid should explore this option further.

In terms of the two views that you are seeking (as outlined at the bottom of the Executive Summary of page 3) on (1) the analysis undertaken and (2) the initial conclusions, we set out our views below.

In terms of (1) we note the comments on page 9 of the consultation document regarding the allowable frequency deviation.

It seems to us that there is a potential discrepancy between the theory quoted in the consultation document and that applied in the analysis. For example, on page 9 of the consultation document it states that “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.”

The equation for the capacity charge given in section 5.8.2 (page 16 of the consultation document) requires a value for allowable frequency deviation (F). In the spreadsheet provided with the (5th July) correction note, F is defined as –0.5Hz for all plant sizes, even though the 1,500MW and 1,800MW units are both larger than the normal loss limit (1,320MW in this scenario) and so on the basis of the above quote (from section 5.8.2) have an allowable frequency deviation of –0.8Hz. There is no commentary to suggest why this is the case. Using F = -0.5Hz pushes a greater proportion of the reserve costs onto >1,320MW units. Using F = -0.8Hz reduces costs for large (>1,320MW) units, with costs for remaining medium to large plant increasing to recover the discount. Whilst the total amount of reserve costs to be recovered remains unchanged, as expected, from the perspective of certain parties, applying F = -0.8Hz for plant rated over the normal loss limit would reduce any benefit from switching to a capacity charge. However, because this is not clear (in the documentation) certain responders to your consultation might underestimate the effect of ECM-19 on their business and thus they might, inadvertently, give an incorrect response to that consultation.

In terms of (2) we note the suggested approach of offering a discount to power stations sized below 350MW. We do not agree with this. We feel such an approach is demonstrably discriminatory.

The suggestion that the difference in treatment reasonably reflects differences in the cost of providing the frequency response services is not born out by the facts, and in particular the May 27th 2008 incident when the 'third dip' in frequency was clearly linked to smaller generators tripping off leading to a further frequency deviation resulting; in conjunction with the two larger unit trips; in demand reduction.

In this regard we would refer you to the Minutes of the second meeting of the "E3C Small Embedded Generation frequency Obligations Working Group" held on 20th March 2009 and, in particular, the comments, attributed to National Grid, on page 2:-

"National Grid commented that Small Embedded Power Stations from ENA data has increased to around 6 to 7 GW and this upward trend will continue. The future growth could include a large volume of domestic/ micro CHP.

National Grid commented that the loss of embedded generation during a falling frequency scenario exacerbates the excursion, potentially increasing the requirement of demand disconnection volumes to arrest the frequency fall and subsequent recovery.

Given the significant volume of embedded generation and the lack of transparency of their operation (current installed capacity of 6 to 7 GW), it will be difficult for National Grid as a System Operator to manage the System in an effective manner and yet maintaining the security and quality of system standards."

These comments clearly indicate to us that National Grid believes that the operation of Small Generators; that is 50MW or less (let alone those of up to 350MW in size); do have a material effect on frequency response requirements, and that this will grow in the future.

As noted in the consultation responses, frequency response is a shared benefit across all generators, irrespective of size (as the May 27th 2008 incident demonstrates).

Arbitrarily excluding a certain class of user (such as sub 350MW generators) from the frequency response costs means that the costs those sub 350MW generators impose on the system will, instead, be paid by other users. This discriminates against those paying users and, particularly with respect to generation, in two meaningful ways.

First, because they pay the costs of the 'excluded' class of generators (e.g. the sub 350MW generators) even though they did not give rise to those costs.

Second, because when competing against the 'excluded' class of generators (e.g. the sub 350MW generators) their price, in the market, will have to reflect this cost whilst the 'excluded' class of generators' prices will not have to reflect this cost (as they do not pay it). Thus not only does such a proposal breach condition 7 of the Transmission Licence it also fails to facilitate effective competition in generation and supply.

In addition to this, if the cost differentials between, say a 349MW and a 351MW power station are significant (due to not paying / paying for frequency response) then this is likely to lead to an unintended consequence (of this change) whereby generators down-size to avoid the cost.

We therefore conclude that of the three charging options set out in the consultation document that the "Commodity Charge" approach (as set out in section 5.8.1) is the most appropriate. For the avoidance of doubt, we do not support either the "Capacity Charge" or the "Banded Commodity Charge" approaches.

We hope you find this comments helpful.

Yours sincerely

Garth Graham
Electricity Market Development Manager
SSE

From: "Sims, Adam" <adam.sims@uk.ngrid.com>

To: "Hynes, Patrick" <patrick.hynes@uk.ngrid.com>, "Kirk-Wilson, William" <william.kirkwilson@uk.ngrid.com>, "Pielage, Iain" <iain.pielage@uk.ngrid.com>, "Spreeuwenberg, Ivo" <ivo.spreeuwenberg@uk.ngrid.com>

Date: 05/07/2010 15:40

Subject: ECM19 - Charging for Large Loss Frequency Response - Notice of Clarification and deadline extension

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Colleagues,

Please note that National Grid has published a Note of Clarification with regard to this consultation on the Charging website: http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/ The note includes a simplified spreadsheet to allow users to calculate example tariffs based on the same assumptions used in the consultation.

To allow users to fully consider this clarification before responding to the consultation, the deadline for responses has been extended by two weeks to **Friday 23rd July 2010**.

Regards,

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Adam Sims
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Appendix 1

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Dear Adam

I am writing on behalf of Westinghouse in response to the consultation document GB ECM-19, Charging for Large Loss Frequency Response.

The consultation document provides a comprehensive analysis of the costs that will be incurred as a result of putting larger generating units onto the national grid system. We believe that the last sentence of section 5.6 provides a very useful summary as follows "This means that for a single baseload 1800MW risk, the additional daily cost directly attributable to it would be £129.6M / 365 = £355k."

The report therefore recognises that an additional annual cost of £129.6M will be incurred as a direct result of adding an 1800MW baseload risk to the system and that no other additional risks at below 1320MW will have any impact upon this additional cost. The report then goes on to consider how the total annual cost of frequency response should be shared between generators. The total annual cost consists of:

£174.6M pa to account for plants up to 1320MW and
£129.6M pa to account for increase in the largest plant from 1320MW to 1800MW,

making a total of £304.2M pa.

It is very clearly right that a utility building new capacity which fits within the current size limit of 1320MW should only be required to pay a proportion of the £174.6M cost of protecting against these risks. They should not under any circumstances be required to contribute towards the additional cost of £129.6M which arises as a direct result of putting a unit of 1800MW capacity onto the system.

The first assumption that is made is that demand will continue to incur 50% of the total response costs as it is the demand Users that require the uninterrupted quality of supply.

Accordingly in the analysis , we have assumed that demand will incur 50% of the total response costs.

The consultation document provides 3 possible charging options, the commodity charge, the capacity charge and the banded commodity charge. These essentially appear to be a reasonable set of options to consider, including a socialisation option, a targeted option and a banded targeted option, although it is unclear how the capacity charge and banded commodity charge are calculated. The capacity charge and banded commodity charge though appear to incorporate an element of socialisation of the costs that a generator bringing an 1800MW risk onto the system brings. This issue is considered further in subsequent paragraphs where we will justify why costs should be targeted at the operators of plants that cause those costs.

We believe that the methodology that National Grid has used to assess the 3 options by looking at whether the option facilitates competition, is cost reflective and permits developments in the transmission business, is sound.

Therefore we believe it is correct that National Grid has identified that a system providing a direct link between the risk that a user imposes and the charge that they pay is essential.

Westinghouse is a supplier of Nuclear Power Stations and in this business competes with other nuclear suppliers. As with all large plant businesses there are economies of scale in the construction of larger plants, which are offset by the additional operating costs that they bring for the grid system. Westinghouse believes that it is fair and appropriate that a generator that chooses to construct a power plant which brings an 1800MW risk should pay the full additional cost of frequency response that they bring, in comparison with smaller plants which would bring no additional cost to provide frequency response.

Any formula which spreads some of the costs associated with a generator that brings an 1800MW risk, onto generators that bring smaller risks would in effect be a subsidy provided by the operators of smaller plants to those operating larger plants. Such a subsidy provided by the operators of smaller plants would be a distortion in the market for the supply of nuclear power stations and could, we believe, be seen as anti-competitive.

Considering the capacity charge, which is the most cost reflective and adjusting the spreedsheet provided by National Grid alongside the consultation to incorporate a risk at 1200MW rather than 1500MW gives a daily capacity charge cost for the 1800MW unit of around £70,000. The consultation though shows in section 5.6 and in Figure 6 that the addition of the 1800MW unit will bring an annual cost of £130-150M, which equates to a daily cost for the generator, assuming that demand pays 50%, of £178-205k. Therefore paying only £70k per day, when bringing a cost of £178-205k per day represents a very significant subsidy for the larger generator.

This can also be seen by comparing the costs that will be paid by the smaller generators under the capacity charge system, to their current costs, without an 1800MW risk. In the above example generators bringing risks of up to 1200MW will pay a daily cost of £321k, which equates to £117M per annum. Section 5.1 and Figure 6 though show that the annual cost for response for risks of up to 1200MW is around £150M, with generation being responsible for half of this number. The proposal therefore transfers £40M per annum of costs from a generator bringing an 1800MW unit onto generators with units no larger than 1200MW. This

analysis though does not take account of the fact that the larger unit will require the full range of response and not simply response covering the increment between 1200MW and 1800MW.

Therefore although we believe that the capacity charge principle is the most suitable one to adopt, we believe that the formula proposed is insufficiently cost reflective. The charging mechanism should ensure that each user pays in full the costs that they impose on the system. Accordingly we have developed a methodology, which we believe achieves the required outcome. The methodology essentially has the generator with the largest risk pay all of the cost associated with the increase above the second largest risk, then a share of all the other risk costs on the system. We believe that this is correct as the largest risk will call upon the full scope of frequency response on the system in the event of failure, therefore must contribute to the total cost of response. The methodology we have employed is for each generator to contribute at each increment in proportion to the quantity of electricity generated. The outcome for a similar theoretical demand day to that used in the consultation is attached as Appendix 1 including a unit at 1200MW rather than 1500MW reflecting the capacity of the Westinghouse AP1000.

This methodology is intended to be fully cost reflective with the generator with the largest risk paying the additional cost that they actually bring and every generator paying a fair proportion of the cost of the response that they rely upon to operate. The key feature of this methodology is that the cost of response per MW of risk rises significantly as the size of the risk increases. This occurs for 2 reasons, firstly the cost of response rises with the level of risk as shown in Figure 6 in the consultation document and secondly as the generator size increases there are fewer other generators with whom to share the cost of the risk.

The methodology applies a large cost of around £108M per annum to a generator that imposes an 1800MW risk onto the system, although this cost can be shared among a number of generators also building large units as can be seen in Appendix 2. Appendix 2 assumes that around 14GW of new nuclear is built, consisting of 4 units at 1800MW and 6 units at 1200MW.

This methodology far more closely aligns with the target cost identified in section 5.9 of the consultation document that adding an 1800MW unit will impose an additional daily cost of £355k or £129.6M per annum. This cost though is shared 50/50 between supply and demand in the allocation model.

In summary Westinghouse believes that a Capacity Charge basis should be used to allocate the cost of frequency response to generators, but that the apportionment formula must be fully cost reflective so that generators pay in full the costs that they bring, as a result of putting larger risks onto the grid system. We believe that the model we have proposed reflects these principles more appropriately than the one proposed in the Consultation Document

Yours sincerely

Dave Mills
Head of Commercial – Westinghouse Nuclear Power Plants
Westinghouse Electric UK Limited

Westinghouse UK Regional Office
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Appendix 1

Unit Capacity	Total No Of Units	Gens Required	Electricity generated	Annual Cost of Reserve	50% of Cost of adding larger unit	Share of additional cost £M	Annual Cost per MW of capacity £M
1800	1	1	1800	150	75	108.99	0.0605
1200	1	1	1200	75	49.5	22.66	0.0189
700	4	2	1400	25.5	3.75	3.34	0.0024
650	15	6	3900	21.75	3.75	5.97	0.0015
600	9	3	1800	18	3	1.94	0.0011
550	17	6	3300	15	3	2.58	0.0008
500	32	12	6000	12	3	3.35	0.0006
450	11	4	1800	9	3	0.73	0.0004
400	8	3	1200	6	3	0.31	0.0003
350	9	3	1050	3	3	0.13	0.0001
300	37	14	4200	0	0	0.00	0.0000
250	26	10	2500	0	0	0.00	0.0000
200	22	8	1600	0	0	0.00	0.0000
150	33	12	1800	0	0	0.00	0.0000
100	30	11	1100	0	0	0.00	0.0000
50	148	56	2800	0	0	0.00	0.0000
Total			37450		150	150.00	

Appendix 2

Unit Capacity	Total No Of Units	Gens Required	Electricity generated	Annual Cost Reserve	Cost of adding larger unit	Share of additional cost £M	Annual Cost per MW of capacity £M
1800	4	4	7200	150	75	107.33	0.0149
1200	6	6	7200	75	49.5	32.33	0.0045
700	4	2	1400	25.5	3.75	1.47	0.0011
650	15	6	3900	21.75	3.75	3.18	0.0008
600	9	3	1800	18	3	1.12	0.0006
550	17	6	3300	15	3	1.60	0.0005
500	32	12	6000	12	3	2.19	0.0004
450	11	4	1800	9	3	0.48	0.0003
400	8	3	1200	6	3	0.21	0.0002
350	9	3	1050	3	3	0.09	0.0001
300	37	14	4200	0	0	0.00	0.0000
250	26	10	2500	0	0	0.00	0.0000
200	22	8	1600	0	0	0.00	0.0000
150	33	12	1800	0	0	0.00	0.0000
100	30	11	1100	0	0	0.00	0.0000
50	148	56	2800	0	0	0.00	0.0000
Total			48850		150	150.00	