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17 November, 2010

Dear Stuart,

Project Transmit: A Call for Evidence

Thank you for the opportunity to respond to the above consultation. Our evidence is attached. As you will see we are supportive of the review, but we do not consider that there is presently a need for radical change in the gas and electricity transmission arrangements, which we believe are largely fit for purpose. We would be concerned if major changes were made to the arrangements which did not provide significant demonstrable benefits to the market and customers. This we believe would undermine investor confidence in the GB market at a time when new investment is very much needed. Nevertheless, we do outline some incremental improvements that could be made in both the gas and electricity transmission arrangements.

- In gas, we do not believe that there is a strong case to review the charging methodologies. However, we believe that improvements could be made to the connection arrangements in order to provide National Grid with incentives to connect users in a timelier manner. This could be undertaken as part of the Project Transmit, although care would need to be taken to avoid revisiting the work that has been undertaken by the industry to date.

- In electricity, we do not believe that the charging methodologies require a radical change. In particular, we consider that locational charging is more relevant in present circumstances, where a significant amount of investment is required in generation and transmission, than it has ever has been and should therefore be retained. However, we do believe that a number of improvements could be made to the charging methodologies, transmission licence and CUSC.

I hope you find our submission helpful. Should you wish to discuss any of the views further please contact Richard Fairholme on 02476 181 421 if it relates to our comments on gas, or for electricity matters please contact me on the above number.

Yours sincerely,

Paul Jones
Trading Arrangements

A) Electricity Transmission Issues

General View

1. We believe that an independent review of electricity transmission charging would be helpful. A number of criticisms have been levelled at the present charging regime for a number of years. Whereas some of these may be justified and worthy of further pursuit, others seem to be clear attempts to obtain a specific commercial advantage for particular groups of companies or generation technology types. Project Transmit should of course consider all of the concerns that have been raised. However, assertions must not be taken at face value but assessed against the evidence as whether or not they are indeed founded.

2. Where possible, previous analysis and consultation should be reviewed and reconsidered in order to avoid unnecessary duplication and repetition of effort. For instance, issues such as fixing the length or price of access rights have been considered a number of times over past years and there is no reason to believe that the work carried out previously will have lost its relevance.

3. It would be useful to consider the wider European context of transmission charging. Clearly as market integration becomes more established across Europe, then charging regimes will arguably need to become more consistent. However, the level of consistency will depend on how markets are integrated or linked. A true cross-Europe comparison of transmission charging has not been achieved to date and would be helpful to educate this debate. A complete comparison should not just consider what proportion of charges are paid by generation and demand respectively, or whether or not charges are locational, but should also consider other issues such as the types of costs that are recovered, whether there is deep or shallow charging and the wider interaction the regime has with other elements of the market such as generator despatch, congestion management and energy balancing. This view is important in order to inform the path that should be taken towards further European integration of arrangements, such as adopting an average G=0 charging regime.

4. A key point we would wish to convey is that radical change should only be considered where it is proven that significant deficiencies exist with the present regime and that incremental change is not appropriate to address these. It is always easy for those advocating radical change to characterise opposition to this as parties dragging their feet or promoting self interest. Of course, parties will naturally defend their interests. However, what is important also is regulatory certainty. If companies see the regulatory climate in GB as one which is uncertain and often subject to significant change, then they are more likely to invest in other markets where the value of their investments is less likely to be “wiped out on a whim”. It is not that we believe that investments should not be exposed to changing market circumstances, but that any changes to the framework must deliver significant demonstrable benefits. Of course, the more consistency that can be achieved across

Europe at this stage, the less likely it will be that the arrangements will need to be unwound at a later stage to facilitate greater market integration.

5. Our belief is that the present methodology is largely fit for purpose. The current objectives for the charging methodology, as set out in paragraph 5 of condition C5 of National Grid's licence, do not in themselves conflict with the three key aims of protecting customers, promoting security of supply and providing a low carbon economy. Therefore, there would not appear to be a strong reason for abandoning these. However, if the charging methodologies are brought within the CUSC, it may be helpful if they are also required to meet the objectives for the CUSC in general as set out in paragraph 1 of condition C10. This would ensure that CUSC and charging modifications are assessed on a more consistent basis, which would be particularly important when complementary CUSC and charging amendments are raised.

6. In this response we will endeavour to provide evidence not only on the issues which we believe exist with the current regime, but also to counter other criticisms that we have heard made of the arrangements where we believe that they are incorrect or perhaps have arisen due to a misunderstanding as to how the arrangements work. First we will consider an important element of the present regime which is that of locational charging.

Locational Charging

7. The present charging regime consists of Connection and Local Transmission Network Use of System (TNUoS) charges which are specific to the particular generator and a wider TNUoS charge which differs depending on the charging zone in which the generator is located. This wider TNUoS charge consists of an element which varies by location (the locational tariff) and a fixed element (the residual tariff) which seeks to recover the correct amount of money each year from generation and demand in the relevant proportions. Therefore, both local and wider TNUoS charges vary dependent on the location of the generator.

8. We believe that locational signals are an important element of the competitive generation market. In order to make an efficient generation investment decision which benefits society as a whole, the relevant generation company needs to see as wide a range of the cost implications associated with that decision as possible. There are always tradeoffs that exist between different choices of location or generation technology type. The aim of exposing the decision maker to the widest range of cost signals is to ensure that the best option overall is chosen when taking into account all of these factors. Clearly, transmission costs are incurred as a result of new power projects being developed. As these costs differ according to where that generation project is located then this should be reflected in the charges that the generation company pays for access to the transmission system.

9. However, it would be overstating the situation to say that locational charges play an overriding role in choosing where to locate a power station. In a large

number of cases other factors, such as the availability of land or fuel, play a more dominant influence in this decision. However, locational charges play a role at the margin between two otherwise equally matched options. Locational signals also play a role in identifying those schemes which incur a disproportionate amount of transmission infrastructure. There are always going to be some sites where the burden of providing transmission access outweighs the other benefits associated with building a generation project there. It is important that the decision maker who decides whether or not to site a generator in that location sees the cost implications so that inefficient investment is not undertaken.

10. It has been questioned whether or not the present arrangements are fit for purpose in order to accommodate the amount of investment in generation and transmission that needs to take place in the coming years. We do not know why this would be in doubt. Arguably, a methodology with accurate cost reflective signals is crucial when generators are making decisions on where to build new generation projects, indeed more so than in a more steady state situation where the infrastructure has been built and the focus is on operational efficiency. Therefore, locational signals are currently more relevant than ever.

Do locational charges prevent renewable development?

11. One accusation that appears to have been levelled at the present locational charging structure is that it is preventing investment in the areas with the best renewable resources, such as Scotland. We would disagree. We have not seen any evidence to suggest that this is the general case and indeed we operate power stations in Scotland and the north of England and are developing more in this area.

12. The following generic analysis is useful in terms of assessing the relationship between increases in TNUoS and increased load factors. The purpose of this is to test the extent to which increased TNUoS alone could influence a decision to locate to an area with higher renewable resource. Generally companies are attracted to sites for renewable power, such as wind, by the increased load factors they can achieve. So if a company decides to locate to an area with higher wind resource, can TNUoS differentials alone negate the benefit of that increased load factor?

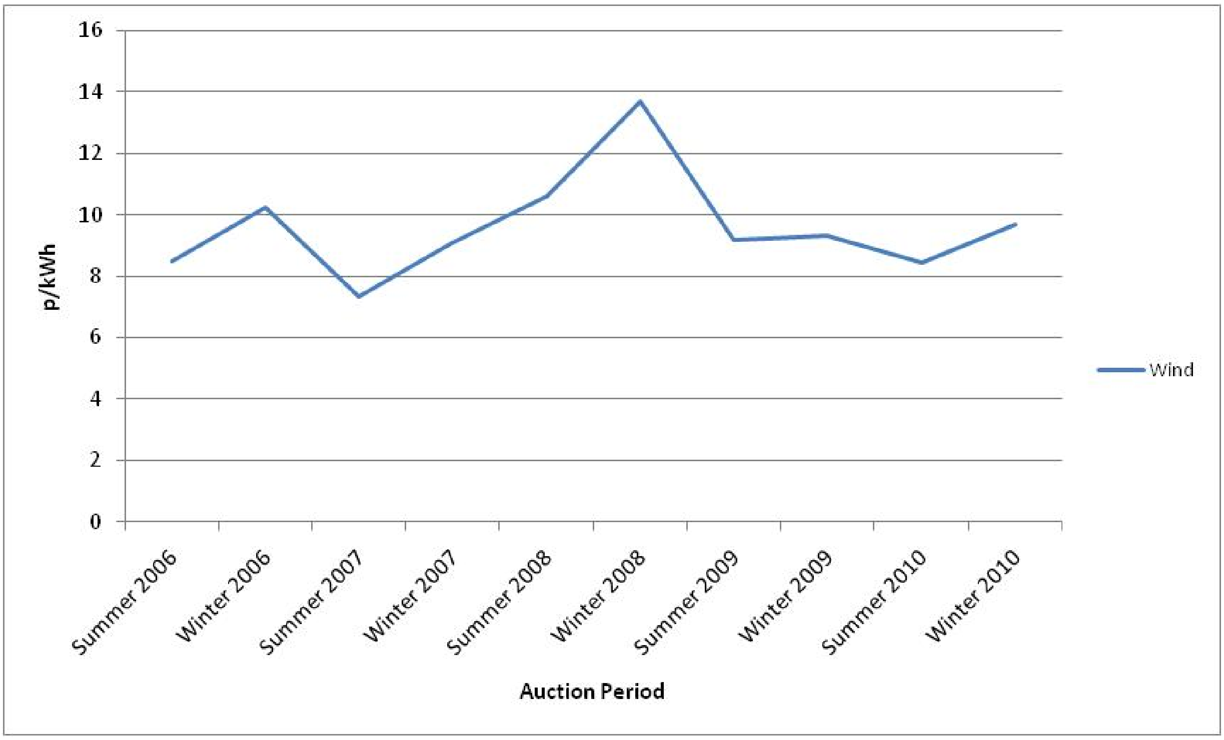
13. As an extreme example, imagine that a developer has the choice between connecting in the lowest priced TNUoS zone (currently London, but Peninsula is very close in value) or the highest (currently Western Highlands and Skye). Now assume that it is attracted to connect in the highest price zone as it will achieve an additional 5% load factor from its renewable generator. The first thing to ascertain is how much that additional 5% is worth in revenue per kW of installed capacity. To calculate this we have looked at past NFFO auction prices for wind projects since the summer 2006 auction period and this is shown in Figure 1 below. This data has been used in order to estimate a market value for wind output, taking into account energy price and

environmental benefits such as ROCs and LECs. The actual average value for the data in Figure 1 is 9.6p/kWh, but for our analysis we have used a more conservative 9p/kWh.

14. A 5% increase in load factor at 9p/kW equates to an additional £39.4/kW of revenue per annum. The present range in TNUoS between these two zones is £29.2/kW so choosing the higher wind resource area would still be worth £10.2/kW per annum net of the additional TNUoS to pay, so it would be well worth choosing this location.

15. Another specific challenge made against the current locational regime is that it discriminates against renewables in Scotland compared with elsewhere in the country. We have calculated the difference between the average generation TNUoS applicable in Scotland and the equivalent figure in England and Wales in 2010/11. The difference between the two areas is about £12/kW[1]. Therefore, if an increase of 5% could be achieved by locating in Scotland then this would net an additional £27/kW per annum.

Figure 1: NFFO Auction Prices Summer 2006 to Winter 2010 per Auction Period

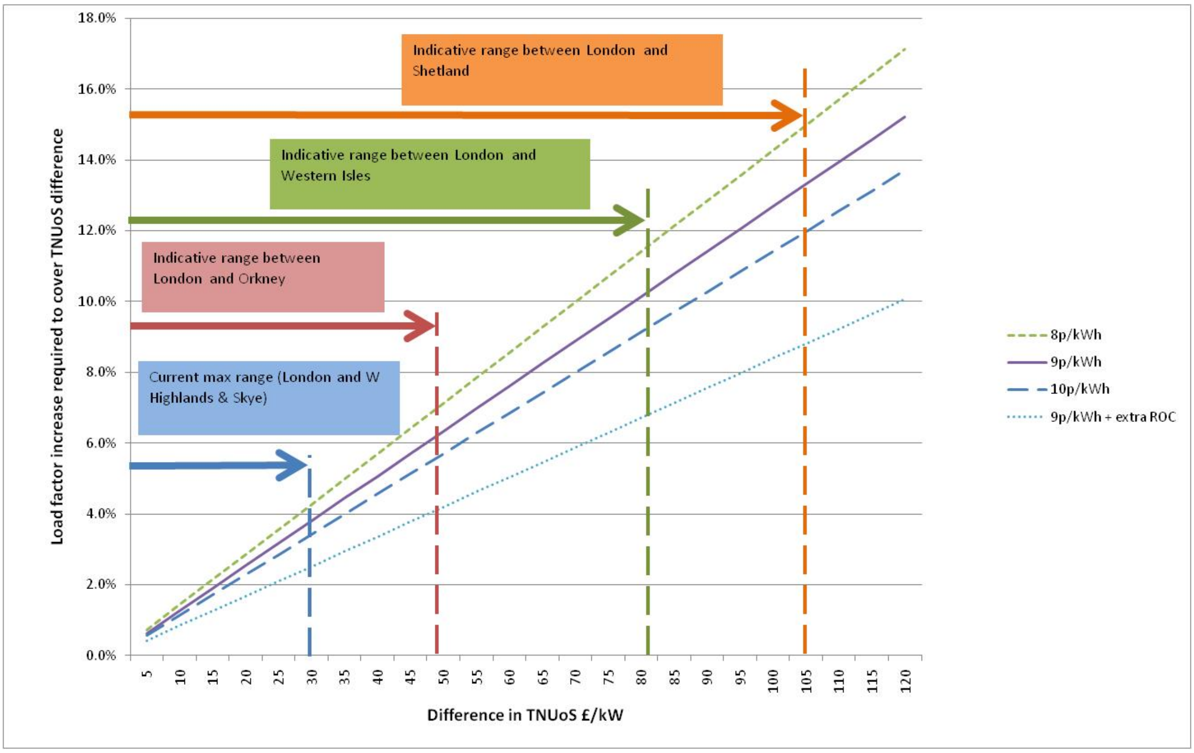


16. Of course, this analysis just considers differentials between existing onshore locations. The situation may be very different for offshore locations or for Scottish Islands. Figure 2 below plots the load factor increases that would be needed to offset various differentials in TNUoS charges. There are four lines

[1] Difference in weighted average TNUoS in Scotland (≈ £15/kW) and that in E&W (≈ £3) weighted by chargeable generation in each zone as detailed in National Grid's TNUoS model for 2010/11

plotted each showing the relationship for differing rates of revenue. The 9p/kWh rate used in the analysis above is plotted, along with lines for 8p/kWh and 10p/kWh to show the sensitivity to changes in revenue rates, and a line showing 9p/kWh plus an additional ROC[2] to illustrate the effects of banded ROCs. The chart also shows illustrative ranges of costs. Along with the current onshore range of costs, there are ranges calculated between the current rate for London and indicative figures for the Scottish Islands which were presented at the March 2010 Transmission Charging Methodology Forum[3].

Figure 2: TNUoS Ranges and Load Factor Increases Required to Offset them



17. What figure 2 shows is that the higher revenue from relatively modest increases in load factors can offset significant differences in TNUoS rates. As you get towards very high tariff differentials associated with the very remote island regions, the load factor differentials required are more significant. However, projects receiving multiple ROCs are significantly insulated from this effect.

18. Of course, these tariff differentials are understandable given the very large distances involved and the cost of the additional transmission infrastructure required. If such high levels of charges indeed result in some schemes not proceeding, it may be that they are not economically viable taking into

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[2] Priced at £4.6p/kWh (price taken from latest e-ROC average price from NFPA website 27 Oct 2010 auction)

[3] These figures were only provided as illustrative, but is the best information available at present

account all relevant cost considerations. If these projects are deemed to still be necessary for other public policy reasons, then we would have no argument with explicit subsidies being provided to provide for this. However, implicit subsidies through the transmission charging methodologies must be avoided as this will distort the arrangements on a wider basis leading to perverse incentives and unintended outcomes.

19. Of course, it is not fully clear what exact charging arrangements will exist for island connections. We have a concern about the inconsistent treatment of HVDC cables in the transmission charging regime which presently causes issues, or may in future, in a number of contexts including the calculation of island tariffs. This is covered later in our evidence, but if this issue was addressed the differentials shown above may not in reality materialise.

20. The above analysis only takes into account the relationship between TNUoS and load factors. Locating to a different location will have a number of different impacts on other costs such as the price of land, manpower costs, rates etc. However, the analysis does provide a useful measure of how likely it is that TNUoS differentials alone could make a significant difference to where power projects are located. It should be noted that the analysis shows a very extreme example of comparing TNUoS rates with Central London (where no significant volume of renewables investment is anticipated). More realistic comparisons with potential sites in the Midlands and North of England would entail TNUoS differentials which are £8/kW to £15/kW lower than for London, with the associated lower load factor increases needed to offset them.

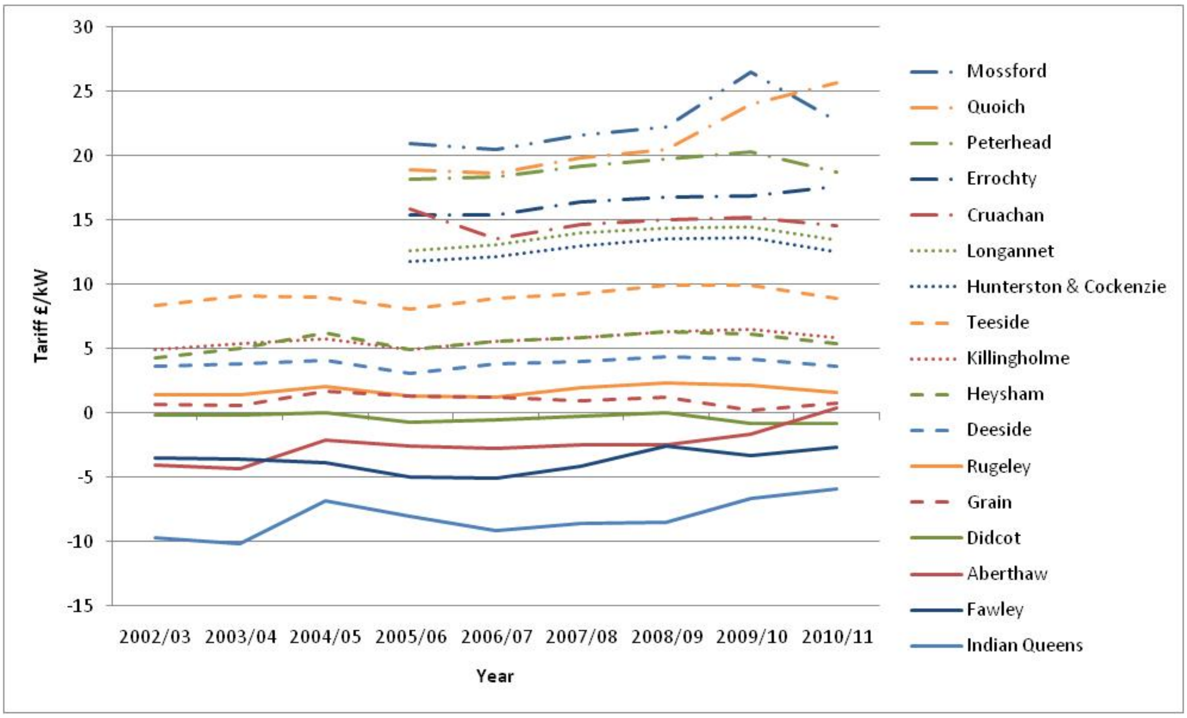
Are locational charges too volatile?

21. Another criticism aimed at the current methodology is that it results in charges which are volatile and unpredictable. Our experience is that charges to particular generators tend to change most when there is a new price control which affects allowed revenue, where a significant change to the methodology occurs and/or when the boundaries of zones change so that a generator is flipped into a higher or lower priced zone. Year on year generation TNUoS charges tend to be fairly stable. Figure 3 shows the charges for a number of stations throughout the country. These have been chosen as representing as many of the present zones as possible. The information for the years 2009/10 onwards shows the wider TNUoS plus the local circuit charge together as this was when this charge was introduced.

22. By and large the charges have been relatively stable. The main increases and decreases occur during the charging year 2009/10 when Mossford and Quoich in particular changed by a relatively large amount. This was caused by the introduction of the local circuit charge, which removed any averaging that occurred in charging for local circuits in the previous average aggregated zonal TNUoS charge.

23. Of course, as more infrastructure is built, which increases allowed revenue year on year, then all generators could see more significant changes in charge. It is not apparent that this will necessarily increase the volatility of the locational signal, but is likely to be reflected through the flat residual tariff which will have to increase to recover the additional revenue. This could be expected to continue for a period of time until new investment in the transmission system slows and allowable revenues stabilise. The point here though is that it is not the locational tariff calculation that would cause the year on year changes, but the increase in allowed revenue. Such changes would affect a flatter charging structure similarly.

Figure 3: Comparison of Combined Wider and Local Circuit TNUoS charges



Fixed charging

24. A further criticism which has been made against locational charging is that it is only possible to influence generators' investment and closure decisions and therefore to impose a charge which changes year on year throughout the life of a project is not relevant. However, the charging methodology cannot second guess when a generator is likely to close its station and apply a fixed value until this point. The charges should be allowed to float so that the generator can come to its own decision based on this signal alongside all other considerations such as anticipated electricity prices, fuel costs etc. Additionally, it is perfectly feasible that a generator may decide to mothball a station part way through its life or partially reduce its capacity in response to market conditions, rather than close it entirely. The avoided transmission charges should be able to form part of that decision.

25. Of course, one option is to provide fixed price access rights for generators who are willing to commit to a number of years' charges. This has been discussed on a number of occasions within the industry and most recently as part of charging change proposal GB ECM-15, which concluded in January 2009 with the view from National Grid and the majority of industry participants being that it would not be appropriate.

26. We remain unsupportive of this option. Our main concern is that the charging methodology is required each year to recover a fixed amount of revenue from all users. If one group of users are able to fix their charges over a number of years, then any year on year volatility in revenue will be pushed onto other parties. As the amount of generation exposed to floating charges reduces then the volatility will become more pronounced. If these generators in turn respond by fixing their charges, then another charge has to be devised to recover any deficit in allowed revenue or redistribute any surplus. This ultimately would result in the volatility being retained, but within a standalone charge which would somewhat negate the purpose of fixing the charges.

Is the methodology too complicated?

27. Some parties have complained that the present methodology is too complicated. However, there is nothing intrinsically complicated about the charging methodology. A cursory glance at the charging methodology statement reveals nothing more taxing than division and multiplication in the calculations. National Grid also provides a model to assist generators in their predictions of future charges. In order to run the model, it is admittedly necessary to make judgements on future plant commissioning and closure and where this may happen, so there is a certain degree of work entailed in order to come up with reasonable assumptions.

28. It could be argued that this disadvantages smaller participants who cannot carry out this modelling. However, it should be borne in mind that generation companies of all sizes are responsible for putting in place multimillion pound civil engineering projects and subsequently operating them and selling their output in volatile energy markets. The engineering, financing and project management challenges associated with this, or dealing with the volatility in future energy prices, are significantly more onerous than those associated with understanding TNUoS charging. We therefore believe that this issue has been somewhat overstated.

29. However, as more investment is made in the transmission network it will be increasingly important that Users are able to predict the allowed revenue year on year so that the impact on their TNUoS charge can be estimated. This is particularly important when considering the effect of offshore transmission tenders and the possible midyear tariff changes that could arise as a result and indeed which we saw occur this year. Midyear tariff changes are particularly difficult for participants to deal with, whether undertaking business planning or pricing contracts for customers. Therefore, we believe that it would be very helpful if National Grid could provide to users sufficient

information, as it become available through the year, in order to allow them to better manage the risk associated with year on year and within year changes in allowable revenue.

Treatment of HVDC Converter Stations

30. By and large we believe that the present arrangements work well. One issue that we have with the present regime is the treatment of HVDC converter stations in various elements of the methodology. This may seem a very specific issue to raise with the methodology, but we believe that its impacts are significant and are attracting criticism of the wider methodology in general as well as its application to offshore and island connections.

31. Presently, the charging model scales the length of lines and cables in relation to how much they cost relative to 400kV overhead lines. For instance, 275kV overhead line is estimated to cost 14% more than 400kV overhead line to transmit 1MW over 1 km (per MWkm). The way that the model reflects this is to multiply the length of these lines by 1.14 and apply a common cost per MWkm (the Expansion Constant) to the results. This avoids applying the specific costs to each relevant circuit in the model.

32. The Expansion Constant includes a number of costs associated with building 400kV lines including an allocation of a proportion of transmission company overheads. However, it does not include the costs of substations assets. The argument that has been given for this is that substation costs are not proportionate to the number of MWkm transmitted. This is an explanation that we have accepted in the past. However, National Grid's treatment of HVDC converter stations in relation to the expansion factors calculated for offshore transmission, and in relation to indicative costs provided for the proposed HVDC bootstrap links for the transmission system, is to include the costs of HVDC converter stations. This is inconsistent with the treatment of substations costs for overhead lines.

33. The reason given for including the converter stations is that HVDC cable is only able to be used in conjunction with converter stations and to ignore the costs would be to understate the cost of this technology[4]. That is, the cost per MWkm of DC cable may be cheaper than the AC equivalent, but you can only use it because you have converted to DC using converter stations, and vice versa. However, the exact same logic applies to 400kV overhead lines. This voltage is cheaper per MWkm than other line voltages or other technologies, but in order to use it power needs to be transformed to and from 400kV within substations.

[4] See paragraph 4.30 of National Grid's conclusion document on GB ECM-24 http://www.nationalgrid.com/NR/rdonlyres/BE81D323-085D-4FA0-98CC-D6D655206A39/41813/GB_ECM24_OffshoreChargingUpdateConclusionsReport.pdf

34. The fact that the transformers in substations convert voltage whereas converter stations convert between alternating and direct current is irrelevant. They both allow use of cheaper lines and cables per MWkm and their costs do not change in proportion to the MWkm transmitted. Therefore, we believe that treating them differently in inconsistent as discriminates against generators who are more exposed to the cost of DC assets.

35. Therefore, we continue to believe that HVDC converter costs should be treated in an equivalent manner to onshore substation costs and be removed from locational signals. We believe that this would:

    1) Provide more appropriate treatment of these assets in offshore local circuit charges by reducing them for HVDC solutions. We could support the cost of the offshore HVDC converter station being included in the local substation charge, but cannot see why both the onshore and offshore stations should be incorporated in the cost of the circuit.

    2) Reduce the present high cost of HVDC bootstraps in the transport model which would reduce its sensitivity of the charges to how much the links are assumed to be loaded. A significant amount of concern was raised in Scotland in particular about how HVDC cables would impact on TNUoS charges. This was in part based on very early work from National Grid which was issued in order to promote debate and the position was subsequently refined. However, the main cause of the concern was the relatively high cost per MWkm of HVDC cable which was attributable to the inclusion of converter station costs into the relevant expansion factors.

    3) Reduce the impact of any HVDC costs in tariffs for islands such as Shetland. This would be a similar effect to that for offshore generators in that HVDC costs would not be attributed fully to the cable costs for the respective island link. Again, this would be consistent with the treatment of onshore substation costs.

36. Therefore, we believe that an alternative treatment of converter stations would improve the consistency of the locational charges in a number of areas and would go some way to countering a number of criticisms of the current regime.

Transmission Charging and Licence Exempt Embedded Generation

37. We assume that the transmission charging arrangements for licence exempt embedded generation is to be reviewed as part of Project Transmit, not least in light of the work on GB ECM-23 ceasing in light of the announcement of the project and the subsequent proposal to extend the provisions of condition C13 of National Grid’s transmission licence. We remain very concerned about the prospect of such embedded generators being charged TNUoS on a gross basis. The present charging regime works on the basis that it is net flows onto and off the distribution network that are important, in terms of how

transmission infrastructure is built and how charges are levied for its use. Adopting a gross charging methodology would represent a huge shift in how these generators are charged which would significantly undermine existing investment decisions and those planned for the near future.

38. The element which is considered problematic is the residual tariff. National Grid believes that the supplier and demand residual tariffs that are avoided are acting as a signal for generators to connect to the distribution system rather than the transmission network. However, the picture is not as simple as this as it ignores the distribution charges generators are exposed to when they connect to the distribution system. Therefore, when deciding whether or not to connect to the transmission network or distribution network, in charging terms, generators make a trade off between the transmission charges that they would be exposed to with a transmission connection versus the distribution charges they would face if they were embedded (along with any share of avoided supplier charges they may share).

39. Of course there are other non charging considerations. One major issue is the firmness of access rights. Transmission connections generally provide greater levels of redundancy in network design along with some compensation for loss of access rights. Distribution connections do not provide the same level of firmness for loss of the distribution network, or indeed the transmission network.

40. Therefore, there are several considerations that generators have to consider when choosing what connection to adopt. What is clear is that the gross charging regime that has been proposed up to now would tip the balance unduly in favour of the transmission network. This is because the difference between a distribution and transmission connection in future will be that the distribution connection will attract distribution charges as well as transmission charges, whereas a transmission connection will only attract transmission charges and not distribution charges. Up to now generators have only been charged for the network to which they are connected. Gross TNUoS charging would change this principle for one class of generators alone, those connected to the distribution network. Not only will this cause considerable financial harm to existing and planned projects that have assumed the current regime and thereby undermine investor confidence in the regulatory regime in GB, but it will undermine efforts to promote more localised distributed generation.

Security Cover for New Connections

41. Security cover for new connections is an area which has attracted a lot of interest in past years. We have seen a number of changes to the arrangements which have been made in response to legitimate concerns raised by participants about how security cover arrangements have impacted their projects. We continue to be supportive of the present choice of arrangements; Final Sums Liability (FSL) methodology and the Interim Generic User Commitment Methodology (IGUM). Moreover, National Grid's

recent proposals whereby wider works are not covered by the FSL arrangements are particularly welcome.

42. We appreciate that various views exist on the detail of both these methodologies with certain parties preferring one over the other. Therefore, we understand why it may seem appropriate to review the arrangements as part of Project Transmit. We believe that the position arrived at with respect to FSLs whereby only local works are underwritten represents the right approach. We therefore believe that this approach should be extended into the calculation of the IGUM methodology. However, what is most important is that any arrangements that are put in place are done so on an ongoing basis without the expectation that they will be reviewed and revised again in the near future. Uncertainty around future liabilities is a significant concern for developers.

Exporting Grid Supply Points

43. National Grid's Transmission licence defines a Grid Supply Point (GSP) as "any point at which electricity is delivered from the national electricity transmission system to any distribution system". Therefore, there is no concept in the present definition of GSPs delivering power from the distribution system to the transmission system, just the other way round. As more embedded generation commissions and as distribution systems are managed in a more active manner, then it will become increasingly likely that certain GSPs will export onto the transmission system at times or perhaps more frequently.

44. CAP093 was raised in order to change the definition of GSP in the CUSC in order to acknowledge that some GSPs were already exporting at times and were likely to do so more into the future. CAP093 appears to have been rejected largely because it would have brought the definition of GSP in the CUSC into conflict with that in the licence. This is an understandable concern. Nevertheless, the current licence and CUSC definitions do not seem to reflect the reality of what is currently occurring on the network and should perhaps be altered to become more relevant. Clearly, a check would have to be made to ensure that this does not cause any undesirable consequential effects.

Demand Charging

45. Demand charging should wherever possible be consistent with that for generation. Therefore, if any changes are made to generation charging it follows that similar changes should be made in respect of demand charges. Therefore, the implications for both the generation market and the supply market should be considered carefully.

Summary

46. We believe that the current arrangements are largely fit for purpose. Project Transmit should be a focussed intervention to address particular issues which are holding up new development. No changes should be made without rigorous assessment of the perceived problems they are meant to address and where possible existing analysis should be drawn upon to avoid repetition of effort.

47. There, is no clear evidence that suggests that locational signals are not appropriate or that their current levels are detrimental to the market. However, the charging methodology is not presently perfect, particularly in respect of the treatment of HVDC converter stations. We believe that consistent treatment of these assets would have benefits in a number of areas. Any changes that are made to the charging regime should where possible apply in respect of generation and demand.

48. Any significant change in the treatment of licence exempt embedded generation is likely to have a substantial detrimental effect to existing projects. This will undermine investor confidence in the GB market and should not be undertaken lightly. Gross charging of TNUoS would discriminate against embedded connections in favour of transmission connections.

49. There are a number of other areas where consideration under Project Transmit would be helpful in order to promote enduring solutions. These include the issue of security cover for new connections and the treatment of exporting GSPs.

B) Gas Transmission Issues

General View

1. E.ON UK does not believe that the gas transmission charging arrangements are in need of fundamental reform and remain fit for purpose. This is not to say that there are not discrete charging issues which may require review from time to time, but in our view, these can continue to be dealt with most effectively through the gas Transmission Charging Methodology Forum (TCMF). Moreover, with new rights expected to be implemented from 1st January 2011, allowing code parties to raise charging methodology change proposals under the Uniform Network Code (UNC), charging issues can be raised by individual parties as and when they see fit.

2. We are unclear of the benefits of a more wide-ranging review of transmission charging in gas, particularly given that a number of very significant changes that have been introduced to the industry arrangements in recent times and have had little time to "bed down". Notable examples are entry capacity substitution and exit reform, which are expected to have a material impact on the operation and use of the gas transmission network in future. Compounding these changes with further significant reform of the charging arrangements is likely to increase uncertainty and risk for new and existing market participants at a time when investment in and development of, key pieces of infrastructure (such as gas storage and CCGTs) already presents significant challenges.

3. Moreover, we consider that the most pressing problem in gas transmission lies not in the charging arrangements, but in the network connection process, which we do not consider is 'fit for purpose'. We believe that a regime where National Grid NTS faces some of the risk involved in the connection process will deliver a significantly more customer-focused approach from National Grid NTS. We therefore believe it is timely to conduct a review of both the existing NTS (and DN) connection process, but in doing so it is important to be mindful of the on-going bilateral discussions between (some) Shippers and National Grid NTS, which are aimed at improving the connections process. We do not believe that NTS connections *necessarily* has to be dealt with under the auspices of Project Transmit, but placing any review of this area on a more formal footing than currently may have its benefits, such as ensuring connection arrangements at entry and exit are equally robust. To date, bilateral discussions have focused primarily on exit connections, but we are aware of similar frustrations with the current process by gas storage Shippers/Developers at entry, for example.

NTS Connections

4. E.ON UK has long-standing and well-documented concerns with the efficacy of the current NTS (and DN) connection process. Unlike the electricity arrangements, where the connection process is underpinned by both licence and CUSC obligations, National Grid NTS faces no such requirements to

provide a timely and efficient service to those wishing to connect (or amend their existing connection) to the NTS.

5. As Ofgem will be aware, E.ON UK raised UNC Modification Proposal 273 to tackle one aspect of the NTS connections process (feasibility studies), with a view to expediting the process. As work progressed, it soon became clear that feasibility studies are just one part of a much larger problem, which has led to the subsequent withdrawal of UNC Mod 273 by E.ON UK, in order to focus efforts on the entire connection process.

6. In conjunction with E.ON UK, a number of AEP members have met with National Grid NTS to discuss and document existing problems and to draft a potential revised connections process “straw-man”. To date, bilateral discussions with National Grid NTS have generally been positive and have elucidated a number of areas where NG NTS processes can be improved. Notwithstanding the constructive nature of these discussions, we have yet to see formal proposals from NG NTS, which given that connections issues were first flagged in UNC Mod 273 over a year ago, is disappointing.

7. Our key, high-level concerns with the existing NTS connections process can be summarised, as follows:

   - No fixed timescales for any aspect of the connection process.
   - No fixed or capped costs for the connections process – all on a direct cost pass-through basis, which does not incentivise any kind of cost-minimisation.
   - Informal process; lack of communication and transparency.
   - Inflexible terms and conditions offered by National Grid NTS.
   - Changes by NG NTS to connection study requirements and costs, mid-process.
   - Uncertainty as to whether your request is being dealt with on a non-discriminatory basis.

8. A concern we hold in respect of incorporating this issue into Project Transmit is the risk of revisiting much of the constructive industry work that has already taken place in respect of improving the NTS connections process. Therefore, if gas network connections are to form part of Project Transmit, where possible, previous analysis and consultation should be reviewed and reconsidered in order to avoid unnecessary duplication and repetition of effort. However, one area that has not been explored due to the limits of UNC workgroups is whether National Grid’s licence provisions in respect of connections are fit for purpose and we believe this warrants further exploration by Ofgem. Whilst we were pleased to note that network connections are on the agenda for the forthcoming price control review, we consider that this will deliver improvements far too late. There is a pressing need for improvements to be made now.

9. It is unclear whether the remit of Project Transmit extends to the Gas Distribution Networks (GDNs), but we note that the problems faced by

Shippers and Developers through the NTS connections process are very similar to those faced by parties wanting to connect (or amend their existing connection) to the GDNs. Through the UNC Mod 273 development process, it was clarified by the GDNs that (as far as we understand) they have a licence provision which effectively exempts them from specific timescales in respect of connecting large loads to their network. We acknowledge that this may be due, in part, to the small number of requests GDNs face, which are also likely to be diverse in nature, but if you are one of the small numbers of Shippers/Developers affected, the existing "ad-hoc" process is highly frustrating. Again, the absence of fixed timescales and costs is a fundamental flaw in the current arrangements. Moreover, with more diversified sources of supply and demand expected to connect to DNs over the coming years, it is now timely to review the DN connection process to ensure it is able to cope with future demand.

TO Commodity Charge

10. Since this issue is set out in the Project Transmit consultation document as a possible issue for inclusion, we consider it necessary to address it. Overall, we do not believe that this discrete issue is significant enough to merit inclusion in Project Transmit. A variable TO Commodity charge presents challenges to all Shippers in terms of planning, but we no longer see the "ever increasing" TO Commodity charge that was used as the justification for the previous proposals brought forward by National Grid NTS. Moreover, National Grid NTS is now forecasting a *reduction* in the TO Commodity charge, due to higher auction revenues. This indicates that changing the arrangements in-line with the previous proposals would have been hasty and have imposed costs unnecessarily; particularly for those Shippers who obtain capacity via all the auctions in order to maximise efficiency and manage risk. Implementing the proposed changes would have resulted in undue commercial advantage for particular groups of companies, which is clearly not the purpose of charging proposals. If parties still feel sufficiently strongly about the level of the TO Commodity charge, from the 1st January 2011, code parties will be able to bring forward their own proposals, which can then be assessed on their own merits.

11. However, as noted above in respect of gas connections, we believe there are far more significant and pressing issues that the industry as a whole should be focusing its efforts on.