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Dear Anthony,

Electricity transmission charging: assessment of options for change (188/11)

Thank you for the opportunity to respond to this consultation. We have answered the questions posed by the consultation in Appendix 1, but firstly we would like to provide some high level comments.

1 Introduction

We welcome that Ofgem are 'minded to' take forward a change to the existing electricity charging methodology. Whilst we continue to believe that the 'SSE socialised' model (the 'wider' MITS socialised with 'local' treatment of transmission connection assets) is the optimal form of transmission charging for the GB electricity market, we can see merit in taking forward the proposed Improved ICRP model.

We continue to believe that there would have been overall benefits to be had from the SSE socialised model: quick and simple to implement; better chance of meeting the UK, Scottish Government and EU renewable targets; less volatile and risky meaning a lower cost of capital for generators and lower wholesale electricity cost impact.

Notwithstanding this, the analysis presented in the consultation document, combined with the analysis from Redpoint's modelling work, indicates that there are considerable benefits for society generally, and for the environment from moving to a charging approach based on Improved ICRP (compared with the 'status quo' ICRP).

We agree that Improved ICRP better meets the needs of a changing GB generation portfolio (than 'status quo' ICRP), one that has an increasing number of small and variable generators looking to connect to the transmission system. Compared to the existing 'status quo' ICRP, Improved ICRP better reflects the cost that variable renewable generation has on the transmission system and the driver for infrastructure reinforcement. This conclusion parallels the analysis and conclusions of the NETS SQSS review. Under that review it was clear that the transmission network infrastructure was no longer solely being provided for 'peak' requirements but also energy requirements driven by increasing renewable generation connecting to the transmission system. In addition, it is also clear that the justification for funding of actual network build by the GB transmission licensees is also being made for energy rather than peak requirements. This can be seen in the needs case and Ofgem's minded-to statement for funding of the Western HVDC 'bootstrap'.

Improved ICRP also fits better with those calling for incremental change to the methodology, rather than what may have been termed the radical change of moving to a socialised model. It also seems to fit better with the direction of travel in Europe and should avoid policy lock-in, providing of course there is no duplication of locational signals from GB and Europe.

We do however believe that there are further improvements that can be made to Improved ICRP, in relation to: the treatment of the HVDC 'bootstraps'; the treatment of (Scottish) island generation; the use of expansion factors; and the implementation of a floor price on generator TNUoS charges. These are expanded upon below. However, as well as providing our views on the improvements that should be made to Improved ICRP, we would like to provide comments on two areas that are likely to be central to and a focus of attention of the responses to this consultation.

2 (a) Impact of Improved ICRP on Consumer Costs

The first focus of attention is likely to be in relation to the impact of Improved ICRP on consumer costs. We believe that there are weaknesses in the Redpoint modelling in relation to consumer costs and the conclusion that these costs will rise in Improved ICRP. We consider that this is a result of the underlying modelling assumptions and that alternative but equally plausible assumptions would have resulted in more favourable consumer outcomes. We believe that a more appropriate conclusion would be that the cost impact of Improved ICRP versus 'status quo' ICRP is too close to call and that the decision to change the transmission charging methodology should be based on other criteria, such as the improvement in cost reflectivity and the likelihood of meeting renewable targets whilst maintaining security of supply.

The conclusion that the difference between end consumer electricity costs is too close to call is illustrated through the analysis completed by Redpoint, where the cost to consumers is estimated at some £900m NPV through to 2020. As noted by Redpoint, this is less than 0.2% of the overall costs of the power sector. At such a level it is well within what would be regarded as the 'norm' for the inherent modelling inaccuracies resulting from the modelling assumptions associated with this type of complex modelling exercise. This level of price difference is equivalent to changing the efficiency of the average price setting gas-fired generator from 50% to 49.7% over the period to 2021.

It is particularly noticeable that the bulk of the ~£900M cost is due to wholesale electricity price effects. However, we believe that the impact of Improved ICRP on wholesale costs is overplayed, it is highly unlikely that increased levels of wind and reduced levels of negative TNUoS in Southern GB will materially affect the wholesale electricity price to the extent outlined in the Impact Assessment (Figure 13). We believe that the Impact Assessment should recognise that it is as plausible that uncertainty over generation TNUoS charging could lead to a lack of generator investment, which could have a significantly greater reductive impact on generation capacity margins and hence the wholesale electricity price.

Redpoint noted in their June 2011 report "A review of "Project TransmiT: Impact of uniform generation TNUoS prepared for RWE Npower" that

".. it [the modelling methodology] assumes that the charging scenario has no impact on the cost of capital that will be applied to new generation investments. Locational charging is inherently less certain than uniform and so it would be reasonable to assume that a higher discount rate should be used."

Whilst the comparison here is between two locational methodologies, the premise stands, that a more stable compressed spread of TNUoS charges associated with Improved ICRP will result in a lower cost of capital than 'status quo' ICRP.

Another factor that casts doubt on the reliance in the Redpoint modelling of this cost to consumers is that the generation background under the 'status quo' ICRP methodology did not converge in repeated iterations of the 'perfect foresight' modelling. Therefore there is a range of status quo outcomes that an Improved ICRP approach should be compared to rather than a single case. This lack of convergence also supports the conclusion that retention of status quo will lead to higher generation costs through the higher discount rate that will be factored into investment decisions.

Section D.1.3 of the Redpoint modelling report outlines the key problem of tariff instability under 'status quo' ICRP that has not been adequately covered by the modelling and the comparative results. The tabled results show that a credible range of tariffs for Northern Scotland under 'status quo' ICRP is between £10/kW and £60/kW. This factor highlights the impact that continued 'status quo' ICRP derived tariffs will have on generation development. This uncertainty is shown to have a significant impact on renewable generation, constraint costs as well as the commissioning dates for the HVDC links.

However, the modelling does not include the impact that this uncertainty has on the expected returns for all forms of generation. To provide some context to this effect, if we assume that the combined low carbon generation investment alone is of the order of £25bn and that the change in rate of return due to TNUoS uncertainty is 0.5%, then the additional cost of uncertainty due to the 'status quo' ICRP tariff methodology could amount to some £2bn over 20 years. In addition the uncertainty seems to indicate a significant chance of underachievement of renewable energy targets under ‘status quo’ ICRP. By contrast the Improved ICRP results were convergent with *"no significant differences between iterations"* (P103, Redpoint, Dec 20 2011).

This position is also shared by other economic consultants as illustrated by the following extract from NERA 2004, Review of GB wide Transmission Pricing, in relation to ‘status quo’ ICRP (emphasis added):

“Since generators (and end-users) cannot fix the transmission charges on offer today, they are exposed to the risk that NGC will unpredictably change its charges in the future. Investors would therefore be unwise to react to the signals present in today’s charges, and will either diversify their investments (to spread their risks) or concentrate their investments in the central regions (where potential variation in future charges is lowest). This type of reaction undermines the incentives inherent in NGC’s proposed charges and means that the differential impact on certain network users is not economically justifiable. ***Further, the unhedgeable nature of these risks could significantly raise the cost of capital for the industry and hence prices to end-users.****”*

Finally, we also agree with Ofgem’s Impact Assessment conclusion that even if there are higher prices, they could result in a more efficient market outcome on the basis that they more accurately reflect all the relevant costs on those that give rise to those costs. Suppressed electricity prices (by not accurately reflecting all the relevant costs) may be better for consumers in the short term but could ultimately damage consumer interests in the long term as it could impede generation investment and thus curtail the wider benefits that consumers enjoy from the maximisation of competition in generation.

In summary, we believe that the cost impact of Improved ICRP versus ‘status quo’ ICRP is too close to call and that the decision to change the transmission charging methodology should be based on other criteria, such as the improvement in cost reflectivity and the likelihood of meeting renewable targets whilst maintaining security of supply.

2 (b) Improved ICRP Distributional Impacts

The second focus of attention is likely to be in relation to distributional impacts. Inevitably the introduction of a change to the methodology will raise objections to it. Most will be focussed on the financial dis-benefits but argued as principles. There is likely to be strong body of dissent from Southern GB generators as their existing benefits from low or indeed negative TNUoS charges are eroded. However, it should be noted that:

- the current ‘status quo’ ICRP methodology has been in place since 1993;
- National Grid has a licence obligation to keep the charging arrangements under review. This dates back to the vesting arrangements, with the introduction of ‘status quo’ ICRP a result of the first review of charges;
- since 1993 the ‘status quo’ ICRP methodology, based on the transmission requirements at times of peak has largely remained unchanged;

- changes to the methodology have been under consideration since at least since BETTA;
- this proposed change to Improved ICRP can be viewed as an incremental change to the methodology (called for by those in favour of locational charging – many of whom are Southern GB generators);
- in a rational market, responding to the locational costs and signals given by ‘status quo’ ICRP, it would be expected that the geographic location of plant would have moved South and as a consequence the Southern GB generator TNUoS charge would have become less negative or indeed more positive. This can be likened to the outcome of a zonal pricing methodology where, as infrastructure is built and constraints are removed, prices levelise.

Based on the above, Southern GB generators cannot claim that the possibility of a change to the ‘status quo’ ICRP methodology should not have been expected nor can they claim to have any pre-ordained locked-in rights to negative or low TNUoS charges. For example the tariff for the history of the Anglia TNUoS region has varied from (negative) -£0.2/kW in 1995 to (positive) £2.39/kW in 2012.

Indeed, many Southern GB generators argued for a locational transmission charging methodology rather than a socialised one as (i) it is more cost reflective, (ii) a locational methodology provides a signal for generators to move (perhaps through closure) to locations closer to demand and (iii) that a move to socialised is too radical a change.

On the first of these, staying with the ‘status quo’ ICRP is clearly not as cost reflective as moving to Improved ICRP, therefore those that have argued for a locational methodology should take comfort that Improved ICRP is more cost reflective than the status quo. For the second, those Southern GB generators that have argued for a locational signal have, by implication, argued for an erosion of the TNUoS charge that they currently pay (or receive in the case of negative zones). They cannot therefore claim any locked-in benefits of ‘status quo’ ICRP methodology. Finally, for the third, the move to Improved ICRP can be seen as an incremental change to the ‘status quo’ ICRP, exactly what Southern GB generators were asking for when arguing against a socialised model. It should also be noted that as Improved ICRP has a lower spread of TNUoS charges, this in turn will have less of an impact on generation tariffs, i.e. they will be more stable and in effect lock-in any benefit for Southern GB generators for longer.

It is useful to put into perspective the scale of change that Southern GB generators will face, by drawing comparisons with some plausible net movements of generation plant on the GB transmission system under a circa 20 year use of ‘status quo’ ICRP, and other changes that the industry is to face in the near future, e.g. the UK Government’s Carbon Price Support Mechanism (CPSM).

i) Movement of plant from North to South. With 'status quo' ICRP, the impact of Peterhead power station moving to Cornwall (i.e. Peterhead closing and an equivalent generator opening in Cornwall) would change the Cornish tariff from a (negative) payment of £7/kW to a (positive) charge of £1/kW; i.e. an increase of some £8/kW in Cornwall. In contrast, for the change from 'status quo' ICRP to Improved ICRP, a generator in Cornwall would see its generation tariff of -£7/KW reduce to £-2/kW, a change of only £5/kW.

ii) Significant relocation of generation capacity from North to South. A scenario involving the closure of 5GW in the North and opening of 5GW in the South, a not unrealistic change to generation plant background over the almost 20 years that 'status quo' ICRP has been in place, would result in the Southern generation tariff under the existing ICRP changing from -£7/kW to + £10/kW, a change of some £17/kW.

   As noted under point i) above, under Improved ICRP, a Southern GB generator will see a tariff of -£7/KW reduce to £-2/kW, a change of only £5/kW, significantly smaller than the change resulting from a long run 5GW movement of plant on the transmission system over the life of 'status quo' ICRP.

iii) Comparison with the cost of change potentially experienced by a Northern generator. Under the 'status quo' ICRP approach the TNUoS tariff for a Northern GB generator was modelled by Redpoint as increasing by circa £8/kW in 2021 almost entirely due to the construction of the HVDC 'bootstraps'. This shows that the impact of continued 'status quo' ICRP is much greater in terms of unanticipatable variability of TNUoS charges on Northern generators than the impact of a transition to an Improved ICRP methodology is for Southern generators.

iv) Comparison with the cost of the introduction of the CPSM. The impact of the introduction of the CPSM in 2013 on the cost of a coal generator with a 60% load factor is equivalent to an increase of £22/kW. This will double in 2014 as the CPSM increases in line with the UK Government's stated objective. With Improved ICRP, the average Midlands zone generation TNUoS increase from 2013 to 2020 is some £2.18/kW, a tenth of the increase that will be brought about by the CPSM.

Finally, on the matter of distributional impacts (raised at the recent Ofgem stakeholder event on 6th February 2012), the following table, outlines our modelling of major generator portfolios' in terms of their proportion of GB Transmission Entry Capacity (TEC) and their proportion of generator TNUoS charges under 'status quo' ICRP and Improved ICRP.

Table 1	GW (TEC)	Status Quo ICRP	Improved ICRP
EdF	1st	2nd	2nd

RWE	2nd	6th	3rd
SSE	3rd	1st	1st
E.ON	4th	5th	4th
Scottish Power	5th	3rd	5th
Centrica	6th	4th	6th
Drax	7th	7th	7th

The table shows that under Improved ICRP the largest holder of generator TEC on the transmission system (EdF) would pay the 2nd highest amount of generator TNUoS, the second largest holder (RWE) would pay the third largest amount of TNUoS and the third largest holder (ourselves) would pay the highest amount of TNUoS, whilst the remaining generators would pay TNUoS in proportion to their TEC holding. This is a more proportionate, equitable and cost reflective distribution of generator charges than the current 'status quo' ICRP provides.

In summary, generation is an uncertain (and thus risky) business where change can have a significant impact on the fortune of generation plant in GB. However the changes arising from plant movement as a result of locational signals and other policy areas, such as the UK Government's CPSM, can have a substantially larger impact on generation across GB than the transition from 'status quo' ICRP to an Improved ICRP methodology will have on those same generators.

3 Improvements to Improved ICRP

Improvements that we believe should be made to Improved ICRP are in relation to: (i) the treatment of the HVDC bootstraps; (ii) the treatment of (Scottish) island generation; (iii) the use of expansion factors (iv) the implementation of a floor price on generator TNUoS charges.

i) The treatment of the HVDC bootstraps

We recognise the positive work that has been carried out by the Project TransmiT Technical Working Group in bringing forward a solution to what was a terminal (catch 22) problem with the treatment of the HVDC 'bootstraps' under 'status quo' ICRP. We welcome the changes that have been made, but believe that further changes are required to realise the full benefits of the 'bootstraps' for renewable generation, sustainability and 'learning by doing'.

Both the Scottish island and 'bootstrap' links result from the drive for investment in renewable generation in order to meet the UK and Scottish Governments' renewable energy targets. There is a strong primary argument from a high level wider societal perspective (meeting those targets is for the wider good of society as a whole rather than simply the result of a competitive generation market) that this should mean that the additional costs of transmission investment to allow additional renewable generation to be built in Northern GB or on the (Scottish) islands should not be borne, at the very least, by conventional generation on the 'wrong' side of the link. This principle can be extended to all generation on the 'wrong' side of the link(s). This would imply excluding the 'real' costs of the link(s) from the generation TNUoS tariff calculation and instead using a 'notional' cost that approximately mirrored the situation where the developments were connected by standard transmission overhead lines as used in typical onshore transmission system reinforcement across GB as a whole. This would result in a situation where the 'Northern' and island tariffs used a substantially lower expansion factor than would currently be the case. This treatment would still allow the generation tariff charges to be established on a cost-reflective basis but one that is not influenced by exceptional factors such as the significantly increased cost of transmission build resulting from the difficulties in getting planning for onshore transmission lines which are seen as necessary to meet wider energy policy objectives, which could not have been foreseen when many generators were making their decisions to invest.

There is a strong secondary argument that adds strength to the proposition to treat the costs of the 'bootstraps' within Improved ICRP as if they were onshore overhead lines. Transformers and grid substations are an essential part of the GB transmission system, however the costs of these 'fixed' elements are not included in the 'status quo' or proposed Improved ICRP methodologies. The substations and AC/DC and DC/AC convertor stations make up a significant element of the capital costs of the 'bootstraps' (and indeed Scottish island links). These elements have broadly the same function as transformers/substations have for the onshore transmission system in that they effectively link different elements of the transmission system and therefore there is a clear case for the substation and convertor station costs to be excluded from the costs of the 'bootstraps' on the basis of equality of treatment and non-discrimination with onshore links. Without removal of these costs, the resulting TNUoS charges may prevent the investment in the very generation that the 'bootstraps' are intended to serve.

A third argument is the fact that the HVDC convertor stations can also provide system services (specifically reactive compensation and post-fault power flow redirection) provides a further justification for the case for treating the costs of the 'bootstraps' within Improved ICRP as if they were onshore overhead lines.

A fourth argument in favour of treating the costs of the 'bootstraps' within Improved ICRP as if they were onshore lines rests on the fact that whilst more expensive compared to onshore transmission links, these investments are likely to result in lower levels of cable losses compared to the situation in which the generation was connected by onshore link. This in turn benefits the UK as a whole in that overall less renewable generation capacity would be needed to achieve a given energy target and thus less support in the form of ROCs or Renewable CfD payments would be needed, which would feed through into lower costs for consumers.

A fifth argument supporting exclusion of the convertor costs is that part of the rationale for going ahead with the 'bootstraps' is that the projects provide significant learning opportunities for the UK system as a whole. Given that this benefit will be felt by all GB customers and generators there is a clear case for spreading an element of this cost widely.

A final argument is that the 'bootstraps' help deliver diversity for UK energy supply. They enable the bulk of wave and tidal as well as potentially wind development in areas that are meteorologically diverse from the rest of the UK. The modelling assumes no difference between the deployment of wave and tidal between 'status quo' ICRP and Improved ICRP. We consider that this does not reflect the likely outcome of moving away from 'status quo' ICRP. We consider that the bulk of the UK's likely early deployed wave and tidal is in Northern Scotland, furthermore about two thirds of this is dependent on island interconnectors. Under either 'status quo' ICRP or Improved ICRP (without island tariff relaxation) it is unlikely that much of this will be deployed. We consider that this impact on wave and tidal deployment can be considered to have a significantly adverse impact on sustainability of the UK's energy future.

The Impact Assessment consultation document correctly focuses on the sustainability benefits of a different treatment of the bootstraps. Given the above 'technical' reasons for a different treatment of the 'bootstraps', and the sustainability benefits outlined in the Impact Assessment consultation document, there is a clear overall logic and benefit to removing the HVDC convertor station costs from the expansion factor calculation.

In summary, on the basis of

- strategic governmental imperative driving generation (and transmission) investment as opposed to simplified cost-reflectivity;
- equality of transmission cost attribution;
- additional service provision;
- enablement of greater diversity in the UK electricity background;
- reduced overall renewable energy support; and
- the benefits of 'learning by doing',

the costs of the bootstraps should be treated within Improved ICRP as if they were onshore overhead transmission lines, or as a minimum, with the convertor costs removed.

ii) The treatment of (Scottish) island connections

The arguments for the equitable treatment of the HVDC bootstraps hold equally well for the equitable treatment of island transmission connections. Island transmission links are driven by a strategic governmental imperative as opposed to the result of straightforward generation market competition; they should be subject to equality of treatment of cost attribution through the comparison of the substation and convertor station costs; they too can provide additional service provision through the use of the convertor stations and finally, they reduce overall renewable energy support in the form of ROCs or Renewable CfD payments which leads to a lower cost to consumers.

On this last point, it is worth considering the overall benefits that the connection (to the transmission system) of an onshore wind generator at one ROC can bring compared to the transmission connection costs of an offshore wind generator at two ROCs. Based on average load factors of 40% for onshore island wind generator and 37.6% for offshore wind generation, the cost of the island transmission cables is approximately half the cost of the extra ROC received by an offshore wind generator. That is, the cost of the island transmission cables could be fully socialised and there would no additional end consumer cost (in terms of the price they pay for their electricity) compared to replacing the island wind generation with offshore wind generation. This highlights that without a solution that lowers the cost of the island transmission connections, there is a danger that these island windfarms will not go ahead, and overall, the cost to end consumers will go up as they are replaced by more expensive offshore wind. Given the capability of the islands to provide a least 1GW of onshore capacity this is a not insignificant advantage of excluding the convertor station costs from the island costs.

Improved ICRP would already produce a lower TNUoS charge for island generation than exists under 'status quo' ICRP and that has to be welcomed. However, it would be a tragedy if, having come this far, a complete solution that allowed generation to connect on the islands was not realised. There are a number of options on their own or in combination that could provide a solution. These are considered below.

a) The convertor station costs of the transmission links to the islands is a large part of the cost of the links, somewhere between 20% and 35% of the total cost. This fixed cost at either end of the cable results in large expansion factors being generated by National Grid's Transport Model methodology for calculating the generator TNUoS charge for the islands. Clearly in a model that is rooted on distance (km), such high fixed costs do not fit well. It at least in part explains why a short (50km) cable to the Western Isles has an expansion factor of approximately 45 and that to

Shetland (300km) is less than 20. This by its nature in the model means that the short cable to the Western Isles is twice as expensive as the cable to Shetland. Again, this does not seem to fit with a methodology where generator TNUoS charges increase with distance (km). In addition, as noted below, the generator TNUoS charges for the islands highlight the flaws in the model's use of expansion factors. We therefore believe that there is justification for the convertor station costs to be removed from the calculation of the islands' cables expansion factors.

b) The islands are particularly disadvantaged through the use of expansion factors based on the actual cost of the transmission cable to the individual island. This is not consistent with the approach that Improved ICRP takes for the generality of transmission network infrastructure where the costs of the different elements are averaged across the transmission licensees' areas. It means that a land based part of the MITS will not be burdened with the individual cost of the actual transmission connection. Instead they will get the benefit of averaging across all circuits. This results in a maximum expansion factor of 27.79, the average applicable to 132kV underground cable in SHETL's area. It would seem appropriate that the island connections receive a similar benefit of averaging when their expansion factor goes above that of a 132kV underground cable, i.e. their expansion factor should be capped at 27.79. This would minimise the additional cost of the islands to the equivalent cost on the mainland.

c) These changes to the calculation of the TNUoS charge for island generation are based around the transmission cables becoming part of the MITS and on that basis being treated under Improved ICRP as any other part of the MITS. In our view, there is no need to introduce any changes to the CUSC, that the CUSC already allows for these cable connections to Orkney, the Western Isles and indeed Shetland to become part of the MITS once the cables have gone in and MITS substations have been established on the islands. CUSC Sections 14.15.16 to 14.15.20 refers to this and an explanatory note is attached in Appendix 2 to this response. What is required is that the generation TNUoS tariffs for the islands are calculated as though the cables were part of the MITS rather than in the way that they have been estimated up to this point, as an add-on to the GB mainland tariff.

d) The island transmission cables will become part of the MITS once the cable is in and the MITS substations on the islands are established. As a part of the MITS, the generation tariff calculation should mimic that of a mainland tariff calculation. This does not seem to be the case in the Improved ICRP calculation where the cable cost and tariff is treated as an add-on to the GB mainland tariff. It means that the island generator receives no load factor benefit, unlike all other non-island generation connected to the MITS. If the Improved ICRP model is to be applied consistently, then there should be a load factor benefit applied equally across the board for all generators connected to the transmission system. To do otherwise would be discriminatory.

e) Shetland consumers' excess diesel generation costs are subsidised by the generality of consumers. Some of this additional cost (such as fuel and some operating costs) would be saved if the Shetland diesels are no longer required to run to meet the needs of island consumers and instead the submarine transmission cable provided the bulk energy requirements of the islands' consumers. This cost saving should be credited to the cost of the submarine cable in much the same way that dismantled overhead transmission lines and transformers are credited back to lower the costs of network infrastructure build in the calculation of network expansion constants and factors on the mainland.

In summary, island generation does not appear to be treated in a consistent manner with mainland generation with respect to transmission charges. One or a combination of the above potential solutions could provide an equitable outcome for island generation and realise the benefits to consumers and the environment that onshore island generation would bring.

iii) The use of expansion factors

The 'status quo' ICRP methodology calculates the TNUoS tariff using an expansion constant based on the average costs of overhead lines and cables at their respective transmission voltages. However, we believe that there are fundamental issues with the way the expansion constant is calculated and used. For example, re-conductoring, bundling and up-rating voltage all increase capacity on the transmission network for a fraction of the cost of a new overhead line. Given wider environmental social and cost considerations, new transmission build is frequently seen as a last, rather than first, resort. In addition, in England and Wales, 132kV overhead lines and cables are treated as distribution, however in Scotland, this voltage is treated as part of the transmission network. As the expansion factor for a 132kV overhead line is 2.24, this means both the 'status quo' ICRP and Improved ICRP methodology models attribute a cost that is 2.24 times higher than that of a 400kV overhead line. However, it is unlikely that a prudent operator would generically expand the transmission network using a 132kV overhead line.

Scotland's 132kV transmission network also highlights another fundamental flaw in the transmission charging methodology that manifests itself in relation to any piece of network infrastructure that is not 400kV overhead line. This can be seen in relation to the HVDC bootstraps and island charging (above). A further consideration is the history of the construction of the electricity network in the Scotland, that goes back to the 1930s. The building of these Scottish 132kV circuits was considered by those responsible at the time to be the most economic solution to the levels of generation and demand at the time, yet under the current (and future) ICRP methodology, generation connected at 132kV is disadvantaged through a higher TNUoS tariff than if the line had been unnecessarily built at 400kV.

This is perverse in that it suggests that gold-plating of the transmission network (i.e. building 275kV or 400kV instead of 132kV where 132kV would be the most economic option) or building bigger generation projects than would otherwise have been the case, is the most efficient under both 'status quo' ICRP and Improved ICRP. This point was noted in the response of Strathclyde University to the original Project TransmiT call for evidence; *"The very large difference in 'expansion factors' that represent the relative costs of reinforcements of branches of the network at 132kV and 400kV would seem to suggest that connection of a new generator at 400kV is always the right answer, however small the generator is. In reality, for a particular generator location, the transmission planner will design the connection that is most cost-effective for the industry as a whole, and this may be at 132kV."*

In summary, the use of voltage and technology specific expansion factors is anachronistic. A more equitable solution would be for all transmission lines to be treated as 400kV.

iv) The imposition of a floor price on generator charges

Generation in Southern GB is currently paid to 'use' the transmission system. Yet, it is demonstrably the case that it costs money to build and operate the transmission system for those users – the transmission network built and operated in Southern GB is not 'free'. However, these generators do not pay (but rather are paid) anything for their use of the transmission system. In addition this 'shortfall' (by virtue of the southern generators not paying) has to be paid for by other generators, i.e. Northern GB generators, outwith the negative charging areas. An example of this anomaly, used by National Grid, was of reinforcements to the shared transmission system necessary to connect new generation near London. Once connected, the new user would be eligible for a negative TNUoS charge, i.e. they would be paid rather than pay a charge, yet, to provide the connection, investment of £70/kW would be required.

Another example is from National Grid's statement, in their SO Incentive Consultation 2009, that *"The costs of resolving [transmission] constraints within Scotland are currently forecast for 2010/11 at £110m."* The generation TNUoS tariffs in Scotland are the highest in the GB, specifically to encourage generation to locate in areas closer to electricity demand; i.e. Southern GB, thereby avoiding transmission constraint costs. However, National Grid then go on to state that *"The cost of resolving the main constraint in the Thames Estuary is currently forecast for 2010/11 at £100m"*. The generation TNUoS tariffs in this area are mainly negative. In other words, generators are paid to locate there, despite the fact that additional generation is increasing transmission constraint costs.

Thus generators in positive areas; i.e. Northern GB, pay, (i) the cost associated with their actual use of the transmission system plus (ii) the cost of the Southern GB generators using the transmission system and (iii) the payments made to the Southern GB generators as well, a triple jeopardy.

In addition, currently, demand TNUoS charges are floored at a positive charge whilst negative transmission charges are allowed to flow through to generation TNUoS charges. This creates distortion, discrimination and inconsistency in the charging regime. In our view, flooring generator charges at a small positive charge, reflecting demand charges would remove these distortions and inconsistencies. This would ensure equality of treatment between generation and demand whilst removing the cross subsidy from Northern GB generation to Southern GB generation.

4 Implementation

As noted above, we do not believe that there is any credible reason why existing Southern GB generators have any rightful claim to pre-ordained beneficial TNUoS charges. Given this we consider that a move to a transmission charging approach based on Improved ICRP should be introduced as soon as is practical and that this should include consideration of the key issues noted above in relation to improvements to Improved ICRP being resolved through the CUSC modification process.

Consideration should be given to including the solution to these issues within the directed Modification (if one is issued by the Authority at the conclusion of the SCR process) to allow the CUSC Workgroup to assess these change options in detail and for the Workgroup, industry and the CUSC Panel to provide views on these options. In this way, the Authority can have a comprehensive suite of fully considered and developed options before it when making its decision on a change to the GB electricity transmission charging regime. It would be regrettable if the conclusion of the SCR was so narrowly focused as to preclude other options which could provide a potential improvement on the original Improved ICRP approach.

In our view it should be possible for the Authority SCR direction to be issued to National Grid in a timely manner once this SCR consultation concludes, which would allow National Grid to raise the directed Modification Proposal(s) in time for the April CUSC Panel paper day (19th April 2012). This should allow the CUSC change process to conclude with the delivery of a Final Modification Report(s) from the CUSC Panel to the Authority by early November this year and for a decision, from the Authority, by Christmas 2012. This would allow draft TNUoS tariffs to be produced shortly thereafter and allow the final 2013/14 TNUoS tariffs to be published at the end of January 2013 and come into effect in April 2013.

Furthermore, noting the approach to 'pre-work' that the Authority authorised National Grid to undertake in advance with respect to the Transmission Access Review (TAR) in 2008/9 it should be possible, as the CUSC Modification(s) develop over the coming months, for National Grid to be authorised to undertake similar ‘pre-work’ (as required) for the SCR Directed Modification(s) and associated Alternatives. This might, for example, lead to the production of draft TNUoS tariffs for a number of ‘scenarios’ based on the CUSC Modification(s) developed by the CUSC Workgroup and presented to the Authority in the Final Modification Report later this year. We do not underestimate the huge effort that will be required later this year of the National Grid charging team (and associated supporting functions) to produce these ‘new’ TNUoS tariffs based on the SCR Directed (or other) Modification(s). If this can be facilitated by the Authority approving ‘pre-work’ by National Grid then, in our view, this would be a pragmatic, and efficient, way to proceed. The relatively small cost of this ‘pre-work’ is likely to be far outweighed by the benefits associated with the changes envisages in the Impact Assessment consultation document coming into effect in April 2013, rather than being unnecessarily delayed until April 2014.

I hope you find our comments helpful. Please do not hesitate to contact me or my colleague Angus MacRae should there be anything you would like to discuss.

Yours Sincerely

Robert Hackland

Appendix 1 - Answers to Specific Questions

Q4-1 Do respondents consider that we have appropriately identified and where possible quantified the impacts of the Project TransmiT options ?

We consider that Ofgem has, in the Impact Assessment (188/11) consultation document, largely identified and where possible quantified the impacts of the Project TransmiT options. However, we have some concerns about the over-reliance on some of the modelling results that are inherently very uncertain, don't seem to adhere to what has actually happened in the past and understate the benefits of moving from 'status quo' ICRP to Improved ICRP.

Our main concern is in relation to consumer costs attributed to Improved ICRP. We believe that there are weaknesses in the Redpoint modelling in relation to consumer costs and the conclusion that these costs will rise in Improved ICRP. We consider that this is a result of the underlying modelling assumptions and that alternative but equally plausible assumptions would have resulted in more favourable consumer outcomes. It is particularly noticeable that the bulk of the cost is due to wholesale electricity price effects. However, we believe that the impact of Improved ICRP on wholesale costs is overplayed, it is highly unlikely that increased levels of wind and reduced levels of negative TNUoS in Southern GB will materially affect the wholesale price to the extent outlined in the Impact Assessment (Figure 13).

For example, given the assumption that wind has no capacity we consider that the conclusion that slightly less baseload generation capacity is required under Improved ICRP is flawed. This then undermines the case that wholesale electricity costs increase under Improved ICRP due to the lower levels of generation capacity margin that result (Section 4.29 & Figure 7). We think that this coupled with a somewhat flawed assumption that a significant volume of generation plant with negative TNUoS charges withdraws in 2016-2020 (over and above that which could reasonably be expected to retire under the baseline 'status quo') causes the increase in wholesale electricity costs arising from Improved ICRP to be significantly overstated (compared to the 'status quo' ICRP methodology). If the expected generation plant retiral is sufficient to increase electricity prices, then it is unlikely that the plant would withdraw in practice simply because of a reduction in an inherently unpredictable source of revenue which would be followed by an increase in price.

We consider that the uncertainty around medium and long term TNUoS charges inherent in the 'status quo' ICRP methodology is likely to have a negative impact on the perceived risk of investing in new generation capacity in GB. This impact is likely to have a greater reductive impact on generation capacity margins and hence result in increases to wholesale electricity prices than the impact that is presented as a consequence of a move to Improved ICRP.

Redpoint noted in their June 2011 report "A review of "Project TransmiT: Impact of uniform generation TNUoS prepared for RWE Npower" that

".. it (the modelling methodology) assumes that the charging scenario has no impact on the cost of capital that will be applied to new generation investments. Locational charging is

inherently less certain than uniform and so it would be reasonable to assume that a higher discount rate should be used."

Whilst the comparison here is between two locational methodologies, the premise stands, that a more stable compressed spread of TNUoS charges associated with Improved ICRP will result in a lower cost of capital than 'status quo' ICRP.

We do not believe therefore that consumer electricity costs will rise under Improved ICRP. Instead, we believe that a more appropriate conclusion would be that the cost impact of Improved ICRP versus 'status quo' ICRP is too close to call and that the decision to change the electricity transmission methodology should be based on other criteria, such as the improvement in cost reflectivity and the likelihood of meeting renewable targets whilst maintaining security of supply.

This conclusion, that the end consumer costs are too close to call, is illustrated through the analysis completed by Redpoint, where the cost to consumers is estimated at some £900m NPV through to 2020. As noted by Repoint, this is only some 0.2% of the overall costs of the power sector. At such a level it is well within the 'norm' of what would be regarded as inherent modelling inaccuracies, resulting from the modelling assumptions that arise from this type of complex modelling exercise. This level of price difference is equivalent to changing the efficiency of the average price setting gas-fired generator from 50% to 49.7% over the period to 2021.

Given that the 'status quo' ICRP methodology is the baseline comparison between the models, we also believe that the Impact Assessment should have considered a wider range of possible baseline outcomes. It is apparent that the 'status quo' ICRP methodology is inherently the least stable approach in terms of modelled outcome and one which is patently going to be far from what is really likely to happen (based on historic application of the methodology, generation plant hasn't moved under the 'status quo' ICRP methodology as may have been expected).

In addition, we consider that the impact on negative TNUoS charge zones to be overestimated as it assumes that negative generation charges are sustainable – this clearly cannot be the case and is surely counter to the purpose of either the 'status quo' or Improved ICRP methodologies (Section 4). We consider that the conclusion reached in the Redpoint modelling regarding the siting of low load factor generators is also overstated for this reason.

We think that the level of renewable energy in the 'status quo' ICRP modelling is also overstated. We do not think that sufficient renewable energy overall will be built with the 'status quo' ICRP generation TNUoS tariffs for two reasons. Firstly, with the 'status quo' ICRP generation TNUoS tariffs, renewable generation projects in Northern GB wouldn't go ahead. In addition, balancing new renewable energy in Southern GB wouldn't go ahead due to a variety of (non TNUoS related) reasons including planning limitations, emissions (such as SOx and NOx) air quality restrictions, lack of cooling water abstraction etc., in Southern GB. Secondly, we also consider that the level of biomass is significantly overstated in the 'status quo' ICRP modelling scenario.

Finally, we consider that the positive impact of Improved ICRP in terms of bringing forward more wind generation relative to the ‘status quo’ ICRP is underplayed in the modelling (Section 4.23) which leads to an undermining of the benefits of Improved ICRP compared to the ‘status quo’ ICRP.

Q4-2 Do respondents consider that there are additional impacts which we should take into account in the decision making process and, if so, what are these ?

We believe that the impact that the uncertainty inherent in the ‘status quo’ ICRP approach has on generation investment has not been adequately considered. This uncertainty is likely to result in two impacts: (i) a reduction in the rate of construction of new generation capacity required for system security; and (ii) an increase in the required return on equity rate for new generation projects. Both of these will in effect lead to a larger difference in wholesale electricity prices between the ‘status quo’ and Improved ICRP methodologies than the difference outlined in the Impact Assessment between these two methodologies. On this basis we feel that at the very least the impact of generation transmission charging on wholesale electricity costs (which feed through to end consumer bills) should be considered to be too close to call. This is a very significant factor as it leads through to the change in average bill figures detailed in Figure 14, which we believe to be misleading in relation to Improved ICRP vs the ‘status quo’ ICRP.

Q4-3 Do respondents consider that we have appropriately identified the potential interactions of the Project TransmiT options?

We believe that some of the significant interactions have not been appropriately identified in the Impact Assessment consultation document, to the detriment of a move to Improved ICRP. In particular we consider that the interaction between generation transmission charging and plant location has not been appropriately identified. We consider that the interactions identified do not represent a balanced view of what might happen in two ways. Firstly, we consider that the inherent instability of the ‘status quo’ ICRP generation TNUoS charges has not been appropriately identified and included in the modelling. Secondly, we do not believe that the impact that factors, other than TNUoS charges, have on generation siting have been appropriately identified. The consequence of these shortcomings is that the negative impact of a move from ‘status quo’ ICRP to Improved ICRP is overstated. We consider that on this basis, if this makes the change to Improved ICRP a difficult call to make, that these impacts should be reassessed by Ofgem (assisted by Redpoint). The simplest way to do this would be to perform a further run of the ‘status quo’ ICRP modelling with a revised set of assumptions regarding generation plant capacity and location which would allow another comparison between the ‘status quo’ ICRP and Improved ICRP methodologies to be presented.

Q4-4 Do respondents consider that we have appropriately identified the likely impacts and consequences of these interactions ?

We believe the following impacts have not been appropriately identified and understate the benefits of a move from ‘status quo’ ICRP to Improved ICRP:

The impact of transmission charging on wholesale costs has been inappropriately identified. We consider that the impact that transmission charging has on wholesale prices is too close to call as there are many other possible outcomes that would have the opposite impact to that modelled.

The impact of transmission charging on regional deployment of generation has been inappropriately identified as it suggests that there are more practical deployable options for generation in the South that will occur in a 'status quo' ICRP world. We consider that this results in an overstatement of the MAR and constraint and Transmission loss costs of a move to Improved ICRP.

The impacts of transmission charging on sustainability goals in terms of meeting renewable and low carbon targets have been inappropriately identified. We think that this arises due to over optimistic assumptions regarding the amount of renewable generation deployment that can take place in Southern GB under a 'status quo' ICRP charging regime.

The impacts of transmission charging on meeting security of supply goals have been inappropriately identified. We believe this arises from the security of supply aspects of continued 'status quo' ICRP being underestimated.

We believe if these issues had been modelled with greater balance, the case for the move to Improved ICRP would be significantly more compelling in that the benefits would be more clearly discernible and the consumer costs would be negative or at worst neutral.

Q5-1 Do respondents consider that we have appropriately identified and taken account of the key sustainability issues?

We do not think that certain important sustainability impacts have been taken into account in the Impact Assessment consultation document. In particular, we believe that air quality and water abstraction / use in relation to plant location have not been adequately considered. We believe that lack of consideration of these has resulted in the modelled generation plant portfolio for the 'status quo' ICRP scenario being overly weighted towards Southern GB. This has resulted in an overestimation of the cost associated with moving to Improved ICRP from the 'status quo' ICRP.

We also believe that planning constraints associated with building both conventional and renewable plant in Southern GB has been underestimated in the Impact Assessment modelling. Lack of consideration of this also results in an overestimation of the amount of conventional plant built in Southern GB within the modelling. This results in an overestimation of the increase in transmission losses resulting from a move to Improved ICRP.

In addition, we believe that the assumption of the level of biomass contribution to renewable generation in the 'status quo' ICRP case does not adequately account for the sustainability issues associated with biomass. We believe that the consequence of this is to overestimate the chances of 'status quo' ICRP meeting the UK (and Scottish) Government renewable targets as well as underestimating the potential sustainability costs to GB in terms of fuel transportation, air quality and security of supply issues associated with significant incremental biomass use.

Finally, we believe that the impact of the 'status quo' ICRP on the deployment of onshore wind generation is significantly underplayed in the Impact Assessment consultation document and modelling. We believe that this results in an over estimation of the overall cost of meeting the renewable energy targets for Improved ICRP. We believe that this also results in an overestimation of the apparent transmission cost difference between the 'status quo' ICRP and Improved ICRP.

Q5-2 Do you think there may be long term and strategic benefits associated with the development of HVDC technology, in particular the treatment of converter station costs for links that parallel the AC network, which Project TransmiT modelling has not fully considered because of the timeframe of the modelling (i.e. 2030) and the limited nature of the bootstrap options?

Yes, we believe that there are likely to be long term benefits from at least removing the costs of the converter stations from the costs of the transmission links. It was apparent at the outset of Project TransmiT, that under 'status quo' ICRP, the total cost of the HVDC 'bootstraps' was a potentially terminal (and catch 22) problem for renewable generation in Northern GB. The proposed changes for Improved ICRP will reduce the negative impact of the 'bootstraps' on renewable generation in Northern GB and this is to be welcomed. However, this could be further advanced, and in particular help realise renewable generation in the more peripheral and remote parts of Scotland, in particular the islands, if as a minimum, the converter station costs were removed from the calculation of the costs of the transmission links. As highlighted in the Impact Assessment consultation document, there would be additional benefits from the deployment of new HVDC technology in advancing this particular technology, which would then realise further benefits for renewables in Northern GB. There may also be additional benefits to be had from the advancement of HVDC technology in relation to island transmission links and indeed interconnectors.

We believe that there are six good reasons for considering at least the removal of the converter station costs from the costs of the transmission link. These have been put forward in the opening to our response and are summarised as follows:

On the basis of

- strategic governmental imperative driving generation (and transmission) investment as opposed to simplified cost-reflectivity;
- equality of transmission cost attribution;
- additional service provision;
- enablement of greater diversity in the UK electricity background;
- reduced overall renewable energy support; and
- the benefits of 'learning by doing',

the costs of the 'bootstraps should be treated within the Improved ICRP transmission charging methodology as a minimum as if they were onshore transmission lines. Failing that, the costs of the converter stations should be removed.

Q5-3 Do you have supporting evidence for a different treatment of the convertor station costs for the planned bootstrap HVDC options?

We believe that the alternative treatment of the convertor station costs is best based on the argument that recognises that the only reason for the use of the 'bootstraps' is to meet UK (and Scottish) Government renewable energy targets, that the use of the 'bootstraps' would not be pursued if this was not the case. Rather, cheaper overland upgrades would be pursued which would not have the additional cost of the HVDC 'bootstrap' options. On this basis it seems inconsistent to treat the costs of the 'bootstraps' in a way that affects all generation on the 'wrong' side of the 'bootstrap'. A more appropriate means of treating these costs would be to assume that the cost is equivalent to onshore transmission and that the advantage that is offered by the 'bootstraps'; i.e. that of speed of deployment; is socialised across all GB TNUoS payers. This would replicate the modelling of the impedance of the HVDC links, modelled as though they were AC transmission circuits. Given that a significant amount of the additional renewable energy allowed by the 'bootstraps' will be onshore wind generation, displacing biomass and offshore wind generation, there is likely to be an overall saving to GB consumers through reduced ROC and CfD payments. In addition, modelling without the converter station costs would (as noted in the Impact Assessment consultation document) accentuate the compression of TNUoS charges under Improved ICRP. This outcome is more in keeping with the outcome of what is considered to be the more economically 'pure' zonal pricing methodology, i.e. as transmission infrastructure is built, market prices are levelised.

Appendix 2 - Note on Island Charging

Island charging was raised by National Grid as a potential change to the charging arrangements back in November 2009, through GB-ECM 20. A consultation took place, though no formal conclusions were reached. The issue became overtaken by the Project TransmiT process. From the consultation responses, opinions were split on treatment of the islands. However, it was noted that the Scottish islands are part of the geographic area of the existing transmission and distribution licences; there was no proposed change in legislation to make them part of the OFTO arrangements; and physically, the Western Isles are already connected to the national electricity transmission system with a GSP at Stornoway.

Whilst the issue was discussed at Working Group meetings, it was recognised that further work was needed[1]. Reference was made to changing boundary definitions to recognise that some 'local' assets would transition to 'wider' in the long run, e.g. anticipatory change to wider as a result of demand on the islands. Whilst that is helpful, and would if needed be an approach that we would support, we do not believe that in the case of the Western Isles and Shetland it would be necessary.

CUSC Sections 14.15.16 to 14.15.20 describe the 'Calculation of local nodal marginal km' and in doing so describe what are MITS nodes and in turn in what circumstances generators would be considered to be subject to a local circuit charge. For the purposes of the Western Isles and Shetland, the relevant definitions are in 14.15.17 and 14.15.19:

14.15.17 Main Interconnected Transmission System (MITS) nodes are defined as:

- *Grid Supply Point connections with 2 or more transmission circuits connecting at the site*

and

14.15.19 Generators directly connected to a MITS node will have a zero local circuit tariff.

At present on the Western Isles, the Stornoway GSP has only one transmission circuit and therefore would not be considered to be a MITS node. However, in SHETL's proposals for the islands, the security of the demand on the islands would be increased through the addition of a second transmission circuit into Stornoway GSP. Given Stornoway GSP would then meet with the definition above of a MITS node, any generator connection into the GSP would have a zero local circuit tariff. A generator connection at another point remote from Stornoway GSP would be subject to a local circuit tariff. The cable itself would be part of the NETS (or MITS) – CUSC 14.15.18

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[1] **Comment taken from draft report**

"For a postage stamp model the key choices were eventually narrowed to consider;

i) Removing the 'local' charging boundary and applying a uniform tariff to all infrastructure assets

ii) Retaining boundary but with modifications. One suggested alternative was to recognise that some 'local' assets are likely to transition to 'wider' in the long run (eg anticipatory change to wider as a result of demand on the islands). It was noted that this option, in particular, required further WG input."

"*.... A transmission circuit is part of the National Electricity Transmission System between two or more circuit breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.*"

Similarly, for Shetland, the proposed configuration of the cable and network security for demand on the islands would potentially create three GSPs, each with two or more transmission circuits. In which case should the cable go ahead, any generator connection into any of these GSPs would also be considered to have a zero local circuit tariff. Again, the cable would be considered to be part of the MITS.

The connections to both islands, should they go ahead, would create MITS nodes on the islands, the cables would be considered to be part of the MITS. This treatment of the Scottish islands would also be consistent with the principle that transmission infrastructure that secures demand should always be treated as wider (consistent with demand charges not having a local element).