Ofgem's Call for Evidence: Project TransmiT – a Centrica response

Context

Centrica is pleased to be able to provide input to this project being undertaken by Ofgem and is happy to commit to playing an active role in the process going forward. We fully support an evidence based approach and welcome Ofgem's commitment to gathering evidence from stakeholders prior to establishing the final scope of the project review. Centrica believes that current charging methodologies are capable of improvement but are not fundamentally "broken"; if there is no robust evidence of a problem with particular aspect(s) of charging, then material changes are not needed.

Moving to the wider context, the essential backdrop to all the initiatives and reviews currently underway is the bigger picture of energy policy objectives – i.e. the provision of secure, sustainable low carbon energy supplies, to meet the needs of present and future consumers, at reasonable cost. The most important driver in this area is low carbon generation, requiring massive investment in generation as well as anticipatory capex in electricity transmission in particular, not to mention the physical requirements associated with increasing cross-border interconnection and market coupling. When taken in conjunction with the natural cycle of network asset renewal it is clear that the industry is facing investment demands not seen since the original electrification of Britain.

In gas, the expected development is less dramatic: the principal investment driver will be long term supply security as the UKCS continues to decline, leading to increased requirements for storage and alternative supplies such as LNG imports. The unpredictability of location for such requirements; the global nature of the LNG market and the regas to liquefaction ratio; the uncertainty around the mix of imported gas flows and the likely growing need to address associated gas quality issues; the need for increased interconnection in gas as well as power and the need for highly flexible gas generation to back up intermittent wind may all require network reinforcement to improve capacity flexibility.

In order to target our response to the call for evidence most effectively, we would have found it useful to better understand Ofgem's contextual thinking in proposing Project TransmiT at this particular juncture. While we appreciate the wish not to constrain unduly the evidence received in response to the call for evidence, we believe it would have been helpful for Ofgem to set out, at this early stage, the expected legislative and regulatory frameworks and complementary initiatives driving or supporting the proposed timescale.

In terms of the call for evidence, the objectives of the review lack definition. The scope of TransmiT is potentially very wide, and we are concerned that such a project has been launched when there are a number of other crucial reviews being undertaken, without a clearly framed set of objectives and criteria by which alternative approaches to transmission charging can be assessed[1]. We therefore urge Ofgem to ensure this area is covered explicitly in the subsequent scoping document, together with detail on what issues Ofgem has concluded need to be addressed or which work well and why. The context should include any associated issues within the current regulatory & legislative framework for GB and EU (for example 3rd package implementation from March 2011), as well as the expectation of binding EU network codes in a number of relevant areas such as grid connection and transmission tariffs.

We believe that the uncertainties associated with a number of reviews in the industry presently may mean that completing an effective and efficient review at this point may require an iterative approach. For example, while we support the evidence based approach, we would not wish to see premature

[1] This observation is supported by our experience of the gas entry charging review group during 2009-10, where the early clarification of charging objectives & assessment criteria would have established the basis for a far more effective and successful review

actions undertaken as a result of TransmiT which may subsequently require further significant change due to the outcome of other activities which are already "in flight".

In terms of the ongoing reviews which we believe will be a vital influence on the work of TransmiT, we believe that the key elements are:

1. DECC's Energy Market Review which is expected to publish before the end of the year. We believe that the overall set of incentives for low carbon generation coming out of this work is likely to be more neutral in terms of technology mix than the current approach - and thus strengthen the case for neutrality in the charging regime to support economy, diversity and security in power production

2. RIIO-T1 & RIIO-GD1 – in the context of the range of price control reviews being undertaken over the next 2 years, which will require a clear understanding of the drivers and need for investment; the confidence of investors and financial institutions who will be required to fund the necessary investment; and the appropriate allocation of charges in a stable and predictable framework

3. Ofgem's Significant Code Review on electricity cashout which will take place over the course of 2011 and could result in significant changes to charges for imbalance

4. The fundamental review of NETS SQSS

These reviews will be key, both in terms of context for the work and the timing of outcomes. If, for example, specific charging changes were required, we would like to see the timing of such changes scheduled and co-ordinated with other activities to ensure overall the best cost/benefit outcome available.

The remainder of this paper sets out Centrica's views on whether the existing arrangements are fit for purpose. The paper is structured as follows:

- Requirements from a transmission charging regime
- Principles under which the regime should be structured
- Evidence for change/no change, supported by appendices

Overall, Centrica believes that most aspects of the current system have worked well and as intended, the regime as a whole being basically fit for purpose; however there are some areas where action is needed, as set out in the evidence section. We have also commented on areas which have previously been put forward for amendment where we do not believe the evidence supports a case for material or fundamental change.

Requirements from a regime

When setting out the requirements for a transmission charging regime it is essential to state clearly the underlying objectives, otherwise it is not possible to assess properly whether the current or proposed regime is fit for purpose. It is also important to set out those issues for which the charging regime should not be expected to provide a solution.

Centrica believes that the overarching objective of a robust and efficient transmission charging regime should be to promote the delivery of sustainable and secure energy to present and future customers, at reasonable cost. This requires the regime to:

1. Create incentives for efficiency
2. Encourage appropriate investment
3. Encourage the appropriate location of new resources
4. Be technology neutral; and
5. Facilitate security of supply

A robust and efficient regime which meets the key objective and supports points 1-5 above will be predictable and flexible. In addition, framework stability is vital, given the length of investment life associated with the signals given by the regime - network or generation assets, can have lives of between 20 and 50+ years.

While Centrica wishes to see a broadly stable charging framework, we do not see this as meaning no change, rather carefully thought through, evolutionary change with proper notice and respect for investment and business decisions made based on the existing regime.

As noted elsewhere in the paper, the scale of necessary investment requires that proper recognition is afforded to needs of investors in terms of confidence in the stability of the framework going forward.

Stakeholders may hold a range of views as to other kinds of issues that a transmission regime should address. However, these more specific policy goals (such as a target for renewable generation in 2020) are often best addressed through specific policy measures, rather than making potentially unfocused changes to the transmission charging regime. Such unfocused changes are also likely at best to blunt successful incentives or price signals and at worst create perverse incentives or have other unintended consequences.

Government, via EMR, should provide incentives to encourage the generation mix needed to deliver the defined policy objectives. The outcome of EMR should be to set out the requirements in a clear and coherent framework, providing sufficient confidence to the investors to ensure that the massive investment needed is forthcoming. By contrast it is not the role of a charging regime to "tilt the playing field" one way or the other, in a manner which is not predictable, transparent or underpinned by a well defined set of charging principles and hence not capable of being assessed against measurable criteria. A clear illustration of this principle is provided by the banded Renewables Obligation, which provides calibrated support for technologies in accordance with Government policy decisions rather than distortionary changes to transmission charging methodologies.

Principles under which the regime should be structured

The objectives set out above give context and overall direction to the regime, and a set of requirements that the transmission charging regime should support. To give form and effect to these, a set of clear principles is needed which will underpin the development of the regime and by consistent application, will enable the robust assessment of the framework.

The principles must reflect the key tenets of Better Regulation Best Practice – transparent, accountable, proportionate, consistent and targeted. In the context of TransmiT, we believe that these tenets would give rise to the following core principles:

Cost reflective
Cost reflectivity is a difficult area, since definitions are imprecise and the term can mean different things according to context. The precise way in which a charging methodology gives effect to cost reflectivity may be tempered by having regard to the other charging principles, but the basic concept is that each network user (or set of users) should face charges which cover, at least, the capital and operating costs which they impose (or have imposed) on the system. We have provided additional thoughts on cost reflectivity in Appendix B to this paper.

Sustainable
In this context, this means that charging policy is sustainable, flexible and robust to future change. It should promote choices around least cost/efficient service delivery and provide confidence to investors in terms of the stability of the regime and limitation of shocks. We note that the last fundamental review of electricity transmission charges took place some 15 years ago and (absent good reasons for further major change) it is desirable that the methodology which emerges from Project TransmiT should be similarly robust.

Aligned in terms of incentives
The charging regime must create aligned and non-perverse incentives, both within the segment of the industry and between elements of the value chain. In addition, the incentives must be fully evaluated in terms of unintended consequences and coherence across fuels, for example in the relative locational signals for gas-fired power stations.

Technology neutral
As touched on in the previous section, Centrica believes strongly that support for different technologies is a matter for government policy rather than the charging regime, which should be predictable and non discriminatory.

Predictable, transparent & not unduly complex
It is essential that users of the regime be able to predict the future path of charges with reasonable facility: this requires transparency and avoidance of undue complexity. It is also desirable to ensure that the outputs from transmission charging models (e.g. for calculating LMRC) are not unduly sensitive to very small changes in input assumptions, as this can give rise to implausibly large, unpredictable changes in charges at a given location.

To complement these principles, TransmiT must ensure that a holistic view is taken across the Transmission Charging piece – both gas and electricity - as well as recognising the requirements of the distribution networks and associated charging.

Summary of Evidence

In considering the scope for the call for evidence, Centrica believes that there are areas where change to the current charging regime is required and some areas where no material change is required.

Areas where we believe evolutionary change is needed - primarily:
- Impact of OFTO revenues on onshore TNUoS tariffs and the attendant reduction in the onshore residual tariff
- Lack of transparency and predictability of transmission network and system charging and the resulting highly volatile TNUoS and BSUoS tariffs
- Securitisation of capacity requirements, both in respect of gas and electricity
- Lack of cost reflectivity resulting from the current gas entry charging regime
- Interconnector charging policy; and
- Application of NTS Exit charges to gas produced and delivered into distribution networks from within the distribution network (e.g. bio-methane or coal-bed methane)

We do not believe that material change is needed in the following areas:
- Locational signals in both electricity and gas transmission charging and
- Treatment of exemptible embedded generation

To provide support and evidence for our views we have collated a number of short case studies which we believe illustrate both positive and negative aspects of the existing regimes, as well as highlighting areas for action and some possible next steps. The case studies are summarised in the tables below, with more information being provided in Appendix A to this paper.

In addition, in Appendix B, we have started to explore key aspects of cost reflectivity and note points for consideration. We believe that careful examination of the evidence and the development of a clear definition of what cost reflectivity means in the context of charging is an important piece of work which is essential to underpinning a robust framework for all charging going forwards. A common understanding of such a key element will be integral to a successful outcome for Project TransmiT.

When considering cost reflectivity, while it is relatively simple to assert concepts such as “fair share of cost” and “use of network”, it is more complex to define what this means and to agree the quantum of accuracy required in cost attribution. We support the inclusion of a “reasonableness” criterion based on the fact that extreme accuracy in cost attribution is likely to lead to unacceptable costs and complexity, however, this, also requires agreement.

While the principle of cost reflectivity has long been accepted, based on our review to date, we have not been able to find a clear definition. In order to move forward and address the charging methodologies to be used to apportion the enormous investment required over the next decade, Centrica believes that an agreed position on cost reflectivity should be developed.

Table A: areas for action:

Case Study	Issue	Description	Next Steps
1.	Incorporation of offshore charging into the TNUoS charging methodology	The extension of the onshore TNUoS charging regime and specifically the application of the 27:73 split leads to a lack of cost reflectivity in the resulting tariffs. As generators as a whole only bear 27% of the transmission network operators' revenues, the application of a growing offshore local element within this 27% leads to an effective discount to the onshore generator residual tariff.	One observable way of overcoming this anomaly would be to remove the 'local' costs from the wider TNUoS revenue pot and the 27:73 split. However, it would be appropriate to explore a range of possible ways forward, in line with other areas of the review.
2.	Improvements in transparency and predictability of transmission network and system charging	BSUoS and TNUoS charges are difficult to predict which can have a negative impact on planning decisions The ex-post method of calculating BSUoS rates on a settlement period basis leads to charges that are difficult if not impossible to predict. It has also become harder to predict TNUoS due to incorporation of offshore revenues/new investments/incentives under RIIO and TAR etc. These new drivers are adding to the importance of charging information transparency and improved methods for the management of volatility.	Increased transparency around network revenues and in particular within year changes should be a core plank of the review. Management of volatile and unpredictable charges creates unnecessary burdens for suppliers and generators, additional work is required to address while retaining cost reflectivity.
3.	Securitisation of capacity requirements	The user commitment model for gas NTS entry capacity has been exposed as having loopholes which can (in effect) allow parties holding capacity at a single Aggregate System Entry Point (ASEP) to defer or cancel their financial commitment, while forcing other shippers to pay the shortfall between the value of the original commitment and the amount (if any) actually paid by the original bidder(s). The regime also allows National Grid to collect the full amount of the auction revenues even where it has spent only minimal sums and delivered no additional network capacity or reinforcement. On the electricity side, we believe that the availability of two models of securitising connections (Final Sums and Interim Generic User	In addition to current industry initiatives on the securitisation of gas capacity, in the longer term, Ofgem should amend National Grid's licence to prevent them from collecting unearned revenues in cases where signalled capacity is no longer required, and where no network reinforcement has been undertaken. With regard to electricity, we believe that increased transparency and certainty is required and that

		Commitment) is beneficial in that it takes into account different needs of different developers. Nevertheless, we believe that there should be increased clarity and certainty going forward. For example, the IGUC model has been an interim solution for many years and there is little transparency on the actual relationship between £/kW tariffs and actual costs.	codifying user commitment could help deliver this.
4.	Lack of cost reflectivity resulting from the current gas entry charging regime	Entry capacity auction revenues consistently under-recover against targets, with the shortfall being made up by a uniform TO Commodity charge levied against all gas flows into the NTS, irrespective of the amounts paid in capacity charges or the extent of cost recovery at a given ASEP. This leads to significant disparities in UoS charges for the same or a similar service, distorted incentives on network users (given the excessive level of variable charges) and large unpredictable variations in the TO Commodity charge itself.	Identify potential solutions which solve the problem, while being mindful of Ofgem's grounds for rejecting the previous change proposals. We believe that one option for consideration should be the introduction of a location specific commodity charge which would be geared to ASEP-specific cost recovery and thus enhance cost reflectivity at the ASEP level.
5.	Distortions introduced to the charging methodology due to interconnectors being exempt from TNUoS charges	We believe that the recent exemption of electricity interconnectors from TNUoS charges introduces some significant anomalies into the charging methodology which need to be addressed. It places GB generators at a disadvantage when compared to EU generators given that interconnector users can access the GB market but do not face GB transmission costs.	Centrica believes that correcting the distortions introduced by exempting interconnectors from TNUoS needs to be a central part of this review.
6.	Application of NTS Exit charges to bio-methane and other gas delivered directly into distribution networks	NTS exit capacity and commodity charges are being applied in full to new DN-entered gas projects. As the gas does not utilise the NTS, this is inappropriate and cost reflective.	The application of NTS exit capacity and commodity charges in full is inappropriate for DN-entered gas; appropriately cost-reflective solutions need to be proactively developed by both National Grid NTS and (as a consequence of Exit Reform), the Distribution Networks.

Table B: Areas where material change not required

Case Study	Issue	Description	Next Steps
7.	Support for the principle of locational signals to drive efficient siting of investment	We believe that the continuation of the locational signal in both electricity and gas transmission charging is essential to maintain the signal for the efficient siting of new investment. We do not support the arguments frequently made that the locational charging prevents investment and is redundant because generators are increasingly unable to respond to it. It can equally be argued that there is still significant discretion over where and whether to build given the number of potential generation sites. Hence developers do have substantial scope to respond to the locational pricing signal. We therefore believe that the locational price signal should naturally form part of the normal economic siting decision. In annex A, as an example, we outline some of the rationale behind our decision on where to locate our Langage power station as evidence.	In order to continue encourage efficient investment in the network we believe that it is essential that a locational signal remain in transmission charging. We are open to review any evidence that locational charging could prevent the GB meeting its 2020 renewables targets, but we would emphasise that any subsidy should take place outside the transmission charging regime.
8.	Support for the principle of continued embedded benefits	We are not convinced that a fundamental change to the treatment of embedded generation under the transmission charging methodology is justified. The latest proposals from National Grid did not make a robust case that the current arrangements are not cost reflective, are not in line with key charging principles and also go against Government policy.	We believe that if the charging arrangements for exemptible generation are reviewed as part of TransmiT an independent and detailed study be undertaken to fully calculate the impact if embedded generation on the wider network.

Appendix A: Evidence

Case Study 1:

Issues arising from the incorporation of offshore charging into the TNUoS charging methodology

<u>High level summary</u>

The extension of the onshore transmission charging regime to include offshore generators will in practice have an anomalous impact on TNUoS tariffs. Going forward National Grid's target revenue (TNUoS) recovery will increase to include the OFTO revenue streams and hence both demand and generation elements will increase accordingly – with demand picking up 73% of the new OFTO costs and (all) generators picking up 27% in line with the existing methodology. However, in parallel, the majority of the offshore transmission costs are targeted at offshore generators in their 'local' tariff (circuit and substation tariffs). Given that more than 100% of the OFTOs' required revenue will be recovered, a correction is delivered by reducing the residual element of the onshore TNUoS tariff. Aside from providing windfall gains and losses, this anomaly is an obstacle to cost reflectivity and effective competition.

<u>The problem in more detail</u>

In order to incorporate offshore wind farms into the National Grid charging methodology, the onshore charging regime was almost entirely replicated offshore. Given the relatively high costs of offshore assets, such a wholesale extension of the onshore charging regime has led to an anomalous impact on onshore TNUoS tariffs which cannot be deemed to be cost reflective or logical. The incongruity of this is set out in the following points:

- The extension of the onshore charging methodology offshore means that the current arbitrary 27:73 generator / demand split is also applied to offshore assets. (i.e. 27% of OFTO costs is recovered from all generation customers and 73% from all demand customers)

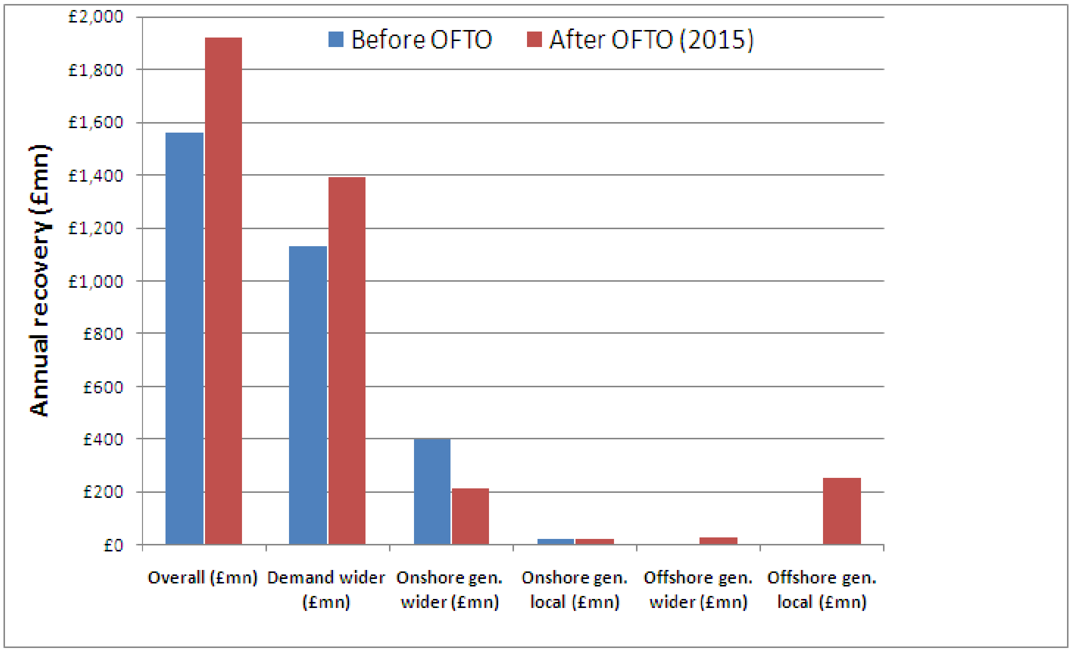
- It should be noted that the current 27:73 generation to demand split is arbitrary and we are not aware that this is supported by the evidence for cost reflectivity or investment signals.

- However, in parallel, the majority of the offshore transmission costs are targeted at offshore generators in their local tariff (circuit and substation tariffs)

- Hence, given that demand customers are liable for 73% of the OFTO costs and a similar percentage is also targeted at offshore generators, there is an over recovery of OFTO costs

- In order to rectify this, whilst complying with the overall 27% attributable to generation, the residual element of onshore tariffs falls significantly, leading to much lower costs for many onshore generators which cannot be deemed to be cost reflective or enhancing competition and has the potential to create significant windfall gains and losses

- The chart below demonstrates the swings in revenues caused by adding the annual projected OFTO revenue of circa £360 million by 2015. As can be seen, this results in the overall amount recoverable from onshore generators being reduced by 50% of the current amount



Conclusion

One observable way of overcoming this anomaly would be to remove both the offshore and onshore 'local' costs from the wider TNUoS revenue. However, we would like to see a range of options examined as part of this review.

Case Study 2:

Improvements in transparency and predictability of transmission network and balancing system charging

High level summary

BSUoS and TNUoS charges are difficult to predict which can have a negative impact on planning decisions. The ex-post method of calculating BSUoS rates on a settlement period basis leads to charges that are difficult if not impossible to predict. Furthermore, it has become increasingly difficult to predict TNUoS due to incorporation of offshore revenues/new investments/incentives (e.g. RIIO and TAR) and the uncertainty around these costs.

The problem in more detail

TNUoS

New drivers of TNUoS costs, such as ENSG and OFTO revenues, are causing both larger year-on-year changes in tariffs and rendering the forecastability of tariffs (once relatively easy) much harder. In other words, different costs are emerging at different times and places and hence it is becoming increasingly difficult to take a view on future years' tariffs. This can represent a significant issue for generators with regard to planning as well suppliers, depending on the contract with customers.

We believe that an increased amount of information needs to be made available to Users to better predict these charges. Currently, National Grid publishes forecasts of locational tariffs for the next 5 years but the residual is not included in forecast. However, the residual makes up most of the TNUoS tariff and it is this residual element of the charge that is becoming more uncertain.

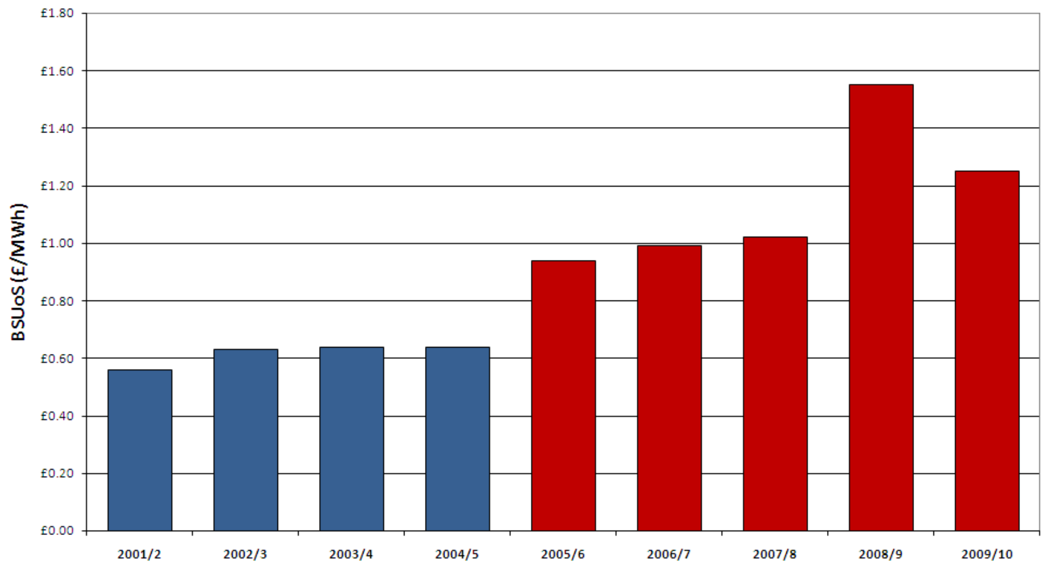
BSUoS

Since BETTA, the level of BSUoS charges has increased dramatically as well as becoming more volatile and unpredictable. Due to the ex-post method of calculating BSUoS rates, this leaves suppliers needing to make a forecast of BSUoS rates when calculating costs for consumers and thus being exposed to fluctuations in BSUoS. The graph below illustrates the range we have seen in BSUoS prices.

Partly as a result of this volatility BSUoS prices have proved difficult to forecast. For example, the National Grid forecast for BSUoS for 2008/9 reported at the February 2008 Operational Forum[2] was £1.18/MWh against an eventual outturn of £1.55 and the National Grid forecast for 2009/10, reported at the April 2009 Operational Forum[3] was £1.47 compared to the actual value of £1.25.

Unlike TNUoS charges, where suppliers have at least some period of certainty due to prospective tariffs being published in advance, suppliers are fully exposed to BSUoS variability per settlement period. Suppliers are therefore obliged to consider methods of managing this volatility and reducing this risk which may well cause extra costs to be borne by consumers. Additionally, the level of uncertainty around future BSUoS charges may affect suppliers' ability to offer longer-term contracts to consumers.

[2] http://www.nationalgrid.com/NR/rdonlyres/86AE3372-4969-413E-A017-2E894CBFF858/23261/Ops_and_SO_Cost_Update_06Feb08.pdf



Conclusion

In order to improve the forecastability of TNUoS, Users require increased transparency from National Grid with regard to regular updates on revenue requirements. Two possible solutions which merit consideration, as presented by E.On at the TCMF on January 27th 2010, are providing a residual forecast in Condition 5 Statements or National Grid providing a register of costs which are likely to be included in allowed revenue for future tariffs which can be updated as new decisions are made.

We believe that a range of solutions should be considered within the review to increase the certainty of BSUoS charges. The range of possible options for consideration should include an ex-ante BSUoS charge and treating the most volatile elements of BSUoS costs (e.g. constraints) in a different way to the other elements.

Case Study 3:

Securitisation of gas and electricity capacity requirements

High level summary

The user commitment model for gas NTS entry capacity has been exposed as having loopholes which can allow parties to defer or cancel their financial commitment, while forcing other shippers to pay the shortfall between the value of the original commitment and the amount paid by the original bidder(s). The regime also allows National Grid to collect the full amount of the auction revenues even where it has spent little or nothing, and delivered no additional network capacity or reinforcement.

On the electricity side, the current arrangements for securitising connections are not codified and are less transparent than other areas which are fully detailed in the various codes. Whilst we believe that the availability of two models of securitising connections (Final Sums and IGUC) is beneficial in that it takes into account different needs of different Users, we would like to increased clarity and certainty going forward both with regard to making the current IGUC methodology an enduring regime and further detail of the link between costs and required securities.

The problem in more detail

In order to trigger the creation of new network entry capacity, shippers are required to bid in a long term capacity auction. The financial commitment provided through the aggregate bids at the relevant entry point must equal or exceed 50% of National Grid's estimated cost for delivering the required volume of capacity.

The current arrangements are deficient in a number of aspects. The bidding party (ies) are not required to place any form of financial surety/security until 12 months prior to the capacity delivery date. (The default lead time for new entry capacity is 3½ years, meaning surety/security is not required until 2½ years after incremental capacity development has been triggered). Within this time circumstances might change meaning that the bidding party no longer requires the capacity it signalled, or does not require it at the time that it is due for delivery.

Where this happens the bidding party may defer its uptake of the new capacity by failing to provide credit. In such circumstances other shippers will be forced to pay the revenues due to National Grid for the release of incremental capacity through a neutrality smear, while the original bidder(s) retain the right to take up the new capacity at a time of its choosing by simply commencing credit payments.

Even where National Grid has spent little nothing on delivering the new capacity, it is still entitled to collect the full revenues signalled through the auction (this may be from non-bidding parties where the default referred to above has occurred). This can only be viewed as a windfall to National Grid.

On the electricity side, we believe that the availability of two models of securitising connections (Final Sums and Interim Generic User Commitment) is beneficial in that it takes into account the differing needs of different users. Nevertheless, we believe that there should be increased clarity and certainty going forward. For example, the IGUC model has been an interim solution for many years and there is little transparency as the actual relationship between £/kW tariffs and actual costs.

There is also a lack of certainty surrounding the arrangements for securing offshore connections in the enduring regime. While there is currently a choice whereby developers have the option of securitising under the Final Sums arrangements for the onshore connection, this remains an interim solution and is not available for the offshore element. The relevant securitisation arrangements therefore need to be addressed as part of the enduring regime.

<u>Conclusion</u>

National Grid is looking at raising a UNC Modification Proposal which will prevent a bidder from deferring their uptake of new capacity. It will achieve this by making the non-payment of credit an event of UNC default (currently non-payment does not result in a formal default). While this might act as something of a deterrent to unscrupulous bidders, it will not in itself prevent the non-payment of revenues by the defaulting bidder from being smeared across other users.

Ofgem is currently consulting on a change to National Grid's licence which will allow shippers to raise an Income Adjusting Event (IAE) claim with Ofgem against National Grid for System Operator Revenue costs. It is the absence of this clause which, at present, means that National Grid can continue to collect all signalled auction revenues (as a windfall, in the Canatxx case).

In the longer term, probably through the next price control, Ofgem should seek to amend National Grid's licence to prevent them from collecting unearned revenues in cases where signalled capacity is no longer required, and where no network reinforcement has been undertaken.

With regard to electricity, we believe that codifying the user commitment options would help bring the much needed certainty to the arrangements for securitising electricity connections and should be used to bring increased transparency between the costs actually incurred by National Grid and level of securitisation demanded from Users.

Case Study 4:

Lack of cost reflectivity resulting from the current gas entry charging regime

High level summary

National Grid seeks to recover 50% of it's allowed TO revenues from entry capacity and 50% from exit capacity. Entry capacity auction revenues consistently under recover against targets, with the shortfall being made up by a uniform TO Commodity charge levied against all gas flows into the NTS, irrespective of the amount already paid by each shipper towards entry capacity through the auction process or the extent of under-recovery against cost (estimated LRMC) at any given ASEP. In some periods this TO Commodity charge is required to recover a greater amount than is realised by capacity charges, (when in principle the element of TO costs which varies directly with throughput is zero) and its level is also difficult to predict,, making business planning very challenging.

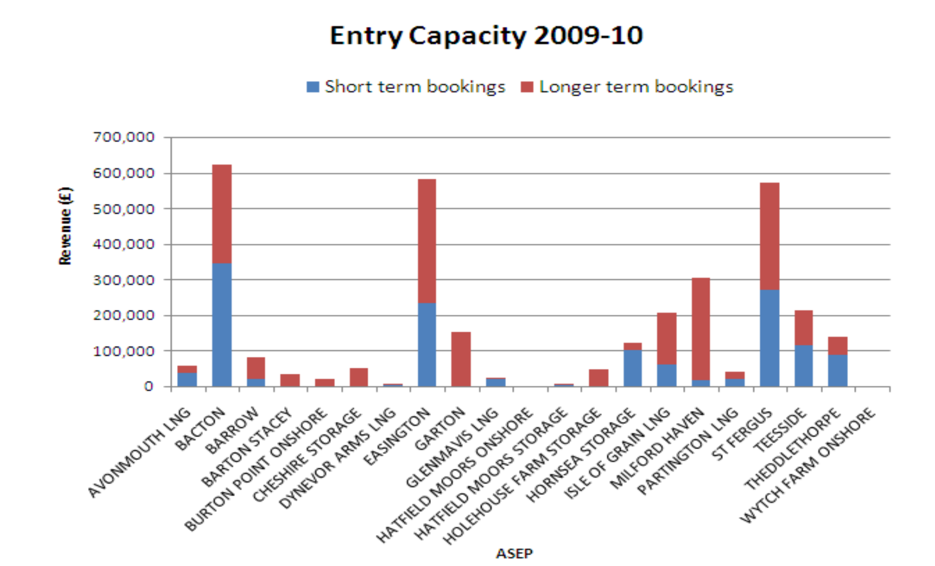
Recently, 18 months' worth of cross industry work to resolve this issue has been rejected by Ofgem, meaning a potential solution could be some significant way off.

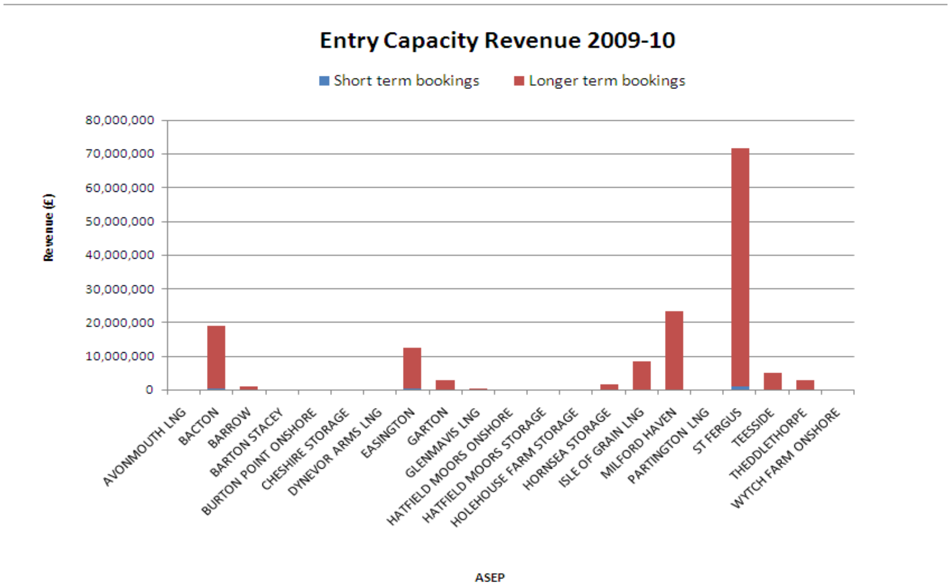
The problem in more detail

A major driver behind the level of this TO Commodity charge has been identified as the short-term entry capacity auction regime which applies discounts of 2/3rds and 100% to reserve prices.

Declining UKCS supplies mean that significant volumes of capacity tend to be available day ahead and even within day, when it is sold at zero reserve price. An incentive therefore exists for shippers to book as little capacity as possible in the full priced longer term auctions (month-ahead and longer), and maximise lower priced shorter term purchases with minimal risk of disruption. In doing so, they face much smaller overall capacity charges plus the TO commodity charge, whereas a shipper who has bought longer term capacity faces the full price for that capacity and the full TO commodity charge rate. Recent attempts to maximise the sale of capacity at full reserve price, for example by limiting the volumes of discounted capacity made available to the market, have been rejected by Ofgem.

The two charts below illustrate the extent of the issue. The top chart shows entry capacity bookings by ASEP, split between longer term (month ahead & longer) and shorter term (DAH and within-day). The lower chart shows the resulting split of revenue accrued from this capacity. As can be seen, the light blue bars have largely disappeared in the chart below indicating the revenues from short-term bookings are minimal.





Conclusion

The solution to this issue is not yet clear, especially in light of Ofgem's recent rejections of UNC Modification Proposals and associated charging methodology proposal, which many believed represented a fair and pragmatic outcome. The challenge now is to identify potential solutions which solve the problem, while being mindful of Ofgem's grounds for rejecting the previous change proposals – in particular, the insistence on a zero reserve price in the short term entry capacity auctions. We therefore believe that one option for consideration should be the introduction of a location specific TO commodity charge which would be geared to recover cost (estimated LRMC) at any given ASEP and thus enhance the cost reflectivity of entry charges as a whole.

Case Study 5:

Distortions introduced within the charging methodology due to interconnectors being exempt from TNUoS

High level summary

We believe that the recent exemption of electricity interconnectors from TNUoS charges introduces some significant anomalies into the charging methodology which need to be addressed. Namely, it places GB generators at a disadvantage when compared to EU generators given that interconnector users can access the GB market but do not face GB transmission costs. The inter-TSO mechanism may not address this where other EU jurisdictions do not have an equivalent level of generator transmission charges. A situation could arise where GB generators, who contribute to the inter-TSO mechanism, are effectively subsidising EU generators' use of the GB transmission system. Furthermore, interconnector flows will still be used to model other users' charges which may result in distortions.

The problem in more detail

We believe that exempting interconnectors from TNUoS introduces 3 key distortions into the charging methodology that need to be rectified.

Firstly, as noted above, we believe that not applying transmission charges to an interconnector (which is essentially a generation and demand unit with a Bilateral Connection Agreement and a registered BMU), risks creating an uneven playing field in terms of the overall charges faced by users of interconnectors (and those that use them) relative to other users.

Secondly, interconnectors receive no price signal to locate in an economically efficient location. For example, an interconnector connecting into Northern Scotland has no incentive to take into account the comparatively high TNUoS charges in that region and make an investment case accordingly. They could also trigger significant investment in the transmission system depending on their location. In this instance however, they would not incur any of these associated costs whilst all other Users would be exposed to the costs of their decisions.

Thirdly, despite the fact that interconnectors do not pay TNUoS, other Users' TNUoS charges would nevertheless continue to be affected by interconnector flows. As interconnector flows would still continue to be modelled in the transport model to provide the best forecast of the background system flows, the impact of interconnectors' presence will continue to be fed through to other users by the locational charge that is picked up by other parties.

Conclusion

Centrica believes that correcting the distortions introduced by exempting interconnectors from TNUoS needs to be a central part of this review.

Case Study 6:

The application of NTS exit capacity and commodity charges to DN-entered gas projects

High level summary

NTS exit capacity and commodity charges are being applied in full to new DN-entered gas projects. As the gas does not touch the NTS this is inappropriate and not reflective of costs.

Problem in more detail

There is a reasonable expectation that there will be a growth in bio-methane projects over the next decade with the vast majority of these sites entering gas directly to the Distribution Networks (DNs). When establishing the first UK bio-methane-to-grid project at Didcot in October of this year it became apparent, through conversations with National Grid and its agent xoserve, that NTS exit capacity and commodity charges would still be applied to this gas, even though the gas will not make use of the NTS.

The root of the problem is that the exit charges are driven by a gas shipper's customer portfolio and the relevant transportation charges are levied on the general assumption that all gas flowing to customers will flow through the NTS.

Initial discussions have been held with National Grid NTS to explore the extent to which these charges should apply, if at all. National Grid presented its initial thoughts to the Transportation Charging Methodology Forum in October 2010 and the Forum agreed that the issues merited further consideration by it. In addition to NTS charges there was discussion on the consequences of NTS Exit Reform, and NTS/DN exit capacity being purchased and paid directly by Distribution Network Owners/ Operators, and system planning.

Conclusion

The application of NTS exit capacity and commodity charges in full is inappropriate for DN-entered gas and appropriately cost-reflective solutions need to be proactively developed by both National Grid NTS and, as a consequence of Exit Reform, the Distribution Network Owners/ Operators.

Case Study 7:

Support for the principle of locational pricing

High level summary

We support the continuation of locational signals in both electricity and gas transmission charging. We believe that reducing the cost reflectivity of the signal would ultimately lead to power stations siting or gas consumption taking place in economically inefficient areas and resulting in investment which would otherwise have been avoided. These extra costs would ultimately feed through as higher prices for consumers.

The problem in more detail

Contrary to some Users' arguments, we do not support the assessment that high locational charges in the north of the UK act as a barrier to investment. The map below demonstrates the amount of renewable generation that has already connected in Scotland. We believe this map clearly illustrates that even with the knowledge that these investments will incur comparatively high TNUoS charges, the economics of the many projects will still be viable. Furthermore, contrary to arguments that potential sites on generators can locate are highly limited, we would argue that there is still significant discretion over where and whether to build given the number of potential generation sites. Hence developers have substantial scope to respond to the locational pricing signal.

Arguments in favour of removing the locational signal from electricity transmission charging have generally gone hand in hand with moving to an energy-based charge rather than a capacity-based charge. We support the principal of a capacity-based charge where the underlying costs are generally fixed rather than short run variable.

We suggest that locational charges are functioning as intended, namely a factor to be taken into account, along with others such as reliability/strength of wind in the decision to site wind farms. Where, for example, wind is strong, reasonably predictable and regular, the certainty of generation and ROC values are likely to outweigh or at least mitigate the increased cost to the network of connection in that area, should this be an area with a higher locational TNUoS charge.

As noted above, we reject the argument that the locational signal is redundant as generators (and especially wind generation) are becoming less able to respond to that signal. The investment decision on Centrica's Langage CCGT Power plant just outside Plymouth was made after careful consideration of all the factors and the locational TNUoS and gas exit charges played a major role in this decision.

Under the current 2010/11 tariffs, Langage could receive in the region of £4.7m in TNUoS payments, coupled with this, it could incur around £5.5m in gas exit charges. The net total of these locational charges is around £750k. However, if Langage was sited near, for example, Humber it could have incurred annual TNUoS charges of £5.2m but much lower gas exit charges of £15k, totalling over £5.2m of potential annual locational charges. *Ceteris paribus*, the difference between the two locations is almost £4.5m per annum, a large incentive to locate in Plymouth and therefore help to avoid costly investments in the electricity transmission system.

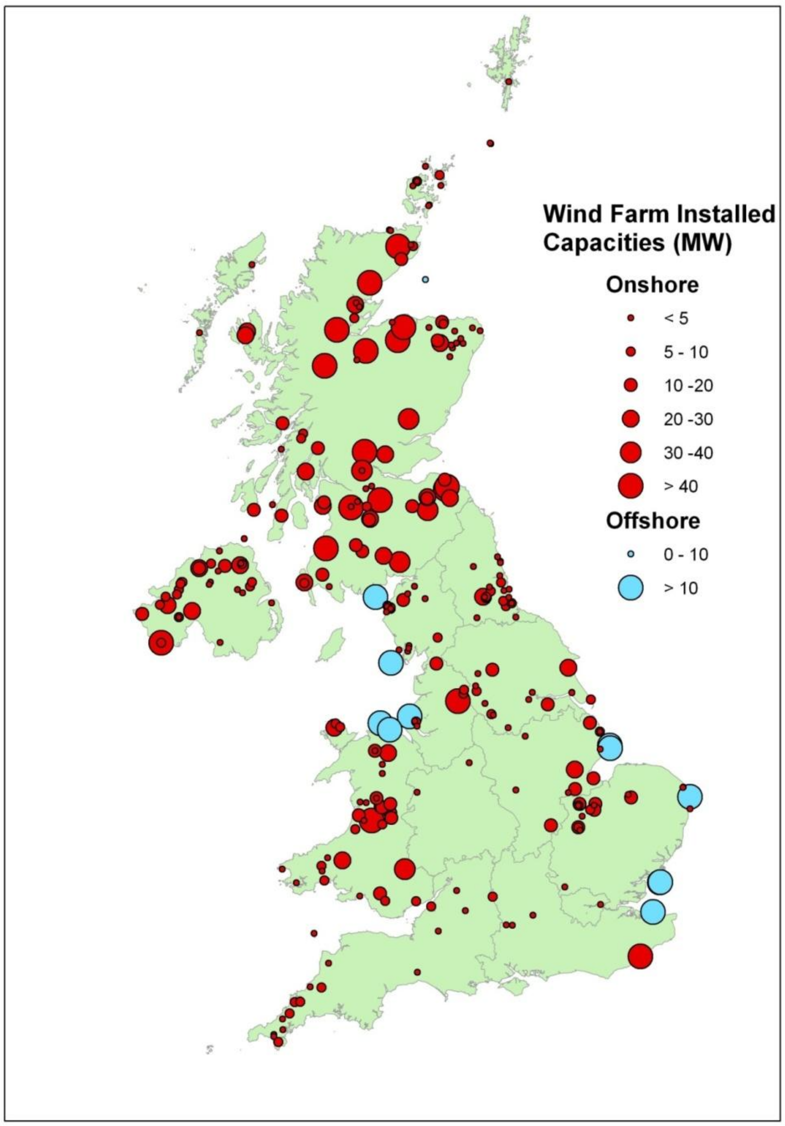
With the move to a low carbon energy future and a shift from gas consumption to electricity consumption, we believe that it is vital that locational signals for the efficient development of the electricity transmission system continue to encourage those investments that will reduce the need to make further investments. Without this locational signal it is highly unlikely that Langage Power

Station would have been built in its current location and the benefits it brings to easing the pressures on the electricity transmission system would not have been realised.

We believe that within a stable and predictable investment framework, locational signals alone should not act to deter investment. If the issues evidenced by the case studies in this annex are addressed (for example predictability of charging and securitisation) then investment will come forward. If the costs of investment in particular technologies remain uneconomic, then this is a matter for a policy decision not removing signals for efficient network development.

Conclusion

In order to continue encourage efficient investment in the network we believe that it is essential that a strong locational signal remains in transmission charging. We are open to review any evidence that locational charging could prevent GB meeting its 2020 renewables targets, but we would emphasise that any subsidy take place outside the transmission charging regime.



Source: DECC website (https://restats.decc.gov.uk/cms/wind-farm-capacities-map/)

Case Study 8:

Support for the principle of continued embedded benefits

High level summary

We are not convinced that a fundamental change to the treatment of embedded generation under the transmission charging methodology is justified. The latest proposals from National Grid did not make a robust case that the current arrangements are not cost reflective and are not in line with key charging principles. In addition to this we believe that they go against Government policy to encourage the development of distributed generation.

The problem in more detail

Under the current transmission charging methodology a distinction is made between directly connected generators and licence exempt distribution connected generators ("embedded generators"). Directly connected generators are liable for TNUoS (and BSUoS) charges whereas embedded generators are not.

The treatment of embedded generation under the transmission charging methodology has been under review since the introduction of BETTA in 2005. However, we believe that despite considerable effort by NG and Ofgem, there is insufficient evidence for the application of TNUoS and BSUoS charges to embedded generators. We therefore remain unconvinced that it is appropriate to consider the introduction of either the "gross nodal supplier agency model" or the "net DNO agency model"; two models proposed by NG that would fundamentally change the charging arrangements.

As we have argued, both NG's models would introduce a significant barrier for embedded generation. In particular we believe that the so-called gross model, favoured only by National Grid and Ofgem, would not be cost reflective, but would instead be discriminatory, complex and discourage generation connecting close to demand. This is not in line with the charging principles discussed in paragraph above and conflicts with Government policy which is committed to driving forward growth in decentralised (renewable) generation.

Investment in embedded generation requires investor certainty about charging arrangements. Given the lack of justification for fundamental change we believe that the review process which started in 2005 should now finally be drawn to a close. The scope of TransmiT should not in our view include further review of the treatment of embedded generation. Any underlying issues, for example information exchange between National Grid and the DNOs, require a targeted solution and should be dealt with separately.

Conclusion

If the charging arrangements for exemptible embedded generation are reviewed as part of TransmiT, then we believe an independent and detailed study should be undertaken to fully calculate the impact of embedded generation on the wider network. We therefore support retention of the current arrangement for distributed electricity generation.

Appendix B:

Cost reflectivity - towards a definition

"Cost reflective" charging is not straightforward in the context of network charging. Cost reflectivity means different things according to perspective and according to the wider context of policy decisions. When considering cost reflectivity it is also essential to decide whether cost reflectivity is the goal at any cost.

Centrica supports strongly the concepts embodied by cost reflectivity in terms of bearing a "fair" share of cost; sending appropriate locational signals and the polluter pays principle. However we do also accept that applying a degree of "reasonableness" may be both pragmatic and efficient, allowing an equitable balance to be struck between cost & risk; complexity & transparency; stability & predictability. The question of cost reflectivity may also raise issues of socialisation vs. accurate attribution. Should a policy decision be required in this context, this would naturally be a matter for Government rather than Ofgem.

While we would welcome the opportunity to debate in detail the issues around cost reflectivity: in this response, we have elected just to indicate key areas of complexity that we believe project TransmiT should examine when reaching a decision on the degree of cost reflectivity required rather than providing a detailed annex on this topic.

Among the complexities that need to be addressed are:

- Anticipatory investment. A network may be built and sized to reflect anticipated future use of the system (generation or demand). Once built, the investment is sunk, and a connecting user would argue that incremental cost is low. This form of low risk "anticipatory" investment may require different treatment to more speculative investment

- Direct and indirect costs. It is debatable whether only costs directly attributable to a user should be charged or whether this should also cover indirect costs

- Treatment of existing users. Existing users do not "cause" long run incremental costs. However, their remaining on the system does prompt the need for reinforcement of the network for other new users. Conversely, it is important to recognise that an existing user, once located, has extremely limited ability to respond to further signals. Incautious treatment of such users may lead to an unacceptable escalation of investor risk with significant consequences for the necessary investment programme

- Sequencing of connections. The order of connections affects perceptions of incremental cost and the costs associated with the constraints created by Connect and Manage policy, can only be mitigated by (anticipatory) investment with all the attendant risks noted above

- Short run vs. long run. The lumpiness of transmission investment means that there is a divergence between prices derived from methodologies based on short run or long run marginal costs

- Use of the actual network design vs. a network model. While incurring additional costs and potentially shorter time periods, the trade offs in terms of accuracy and improved cost reflectivity may be sufficient to justify the additional expense of using an actual network design. A careful cost benefit analysis is required to assess the real value of this trade off

There were a number of academic papers submitted to Ofgem's distribution charges review which contain helpful material for this debate in terms of the possible breadth of views, examples include:

- "Estimates of costs which will be incurred or avoided in the future are the only cost estimates which should influence decisions" (Turvey)
- "Economic efficiency is achieved by sending cost reflective price signals to users of the network so as to influence their decisions with regard to (a) location in the network and (b) patterns of network use and (c) signal need for and location of new distribution network investments, i.e., encourage efficient network investment and discourage over investment. Network pricing based on future network development costs is the primary focus of this report." (Strbac and Mutale)
- "Cost-reflective charging suggests that the tariffs for load and DG should reflect the fixed, capacity dependent and energy dependent components of the underlying costs" (Newbery *et al*)

Moving forward, we would like to see a clearer definition as to what cost reflectivity means. In the context set out above, we believe it is likely that cost reflective charges would incorporate a number of possible elements, which should satisfy two principles:

- The overall revenue collected from network users reflects the capital and operating costs of supply of the of the network services. (Restriction on the level of charges)
- Charge differentials between users reflect the incremental cost that they impose on the network for their location and network use characteristics. (Restriction on the structure of charges)

In reaching a definition of cost reflectivity, it may be helpful, in addition to the points above to consider, for example, refining the definition by reference to concepts such as "long run incremental cost".

These principles mean that cost reflective charges should typically be higher for generators that are remote from load centres, and load that is remote from generation. Larger generators and consumers would also typically expect to pay more, as their transmission capacity demand (in MW/km or equivalent gas measure) will be higher.

Once greater clarity has been achieved on what cost reflectivity in charging means, next steps could include, for example, consideration of the types of products or services to be available, likely costs of provision and whether this might vary plus treatment of required investments.