nationalgrid

National Grid House
Warwick Technology Park
Gallows Hill, Warwick
CV34 6DA

Stuart Cook
Senior Partner, Smarter Grids and Governance
Ofgem
9 Millbank
London
SW1P 3GE

Alison Kay
Commercial Director
Transmission

alison.kay@uk.ngrid.com
Direct tel +44 (0)1926 653090
Direct fax +44 (0)1926 653052

www.nationalgrid.com

17 November 2010

Dear Stuart

Project TransmiT

Thank you for the opportunity to provide a response on Project TransmiT. This response is provided on behalf of National Grid Electricity Transmission plc (NGET) and National Grid Gas plc (NGG). NGET owns the electricity transmission system in England and Wales and is the National Electricity Transmission System Operator. NGG owns and operates the gas transmission system in Great Britain and also owns and operates four of the eight gas distribution networks.

In the main body of this response we present our initial thoughts on the scope and benefits of Project TransmiT. The main focus of our response is to review the applicability of the current regime both now and in the future, and in particular, the appropriateness of the principles upon which the charging methodologies are based. We have also included two annexes that cover both our detailed response to the questions raised in the call for evidence and also set out supporting evidence to the points we raise.

National Grid fully supports the review of charging and connection arrangements for both electricity and gas transmission. We recognise that the primary focus, in the short term, in regard to moving to a low carbon energy sector, will be on electricity arrangements. However due to, for example, the changing nature of gas supply to the UK, and the interaction with electricity generation, a review of the gas transmission charging principles is also timely. National Grid considers that Carbon Capture Storage (CCS) should not fall within the scope of Project TransmiT as it is an unregulated business activity and the primary focus of this review should be the appropriateness of charging current regulated activities.

As an industry we are now moving into a period where the regulatory revenue control arrangements for the next eight years are being developed. As such, we need to ensure that the charging and connection arrangements are consistent with, and effectively complement, the revenue control objectives. This accentuates the need to proceed with the review now and to ensure it completes in a timely manner. The initial focus of Project TransmiT should be to deliver the high level principles and objectives prior to development of revenue control arrangements. This will serve to ensure that the industry has confidence in the stability of the framework moving forward.

The current licence objectives (facilitating competition, cost reflectivity, taking account of developments in the licensees' transmission business, and non discrimination) have to date supported progress toward a low carbon energy sector whilst continuing to meet the broad needs of consumers in an efficient manner. Historically, these principles have held well against an evolving industry background, and remain pertinent going forwards. However, it is essential that transmission licence objectives continue to be fit to deliver the significant challenges of moving to a low carbon energy sector. We suggest that there is merit in considering the relative balance and priority between these objectives, given the critical role that network connections and charging will play in facilitating the wider investment in gas and electricity supply over the next decade. In addition to the current objectives, it is timely to assess whether a new sustainability objective in the licences would better align National Grid's role in the facilitation of industry development with that of Ofgem.

In the areas of both gas and electricity transmission, National Grid is also increasingly being required to comply with European rules. Whilst we consider that, in general, the licence objectives are compatible with these EU rules, Project TransmiT does provide an opportunity to review, confirm and, where necessary, refine the provisions of the licence in this area.

The current charging methodologies for both electricity and gas have been developed to meet the objectives of the licences. National Grid continues to believe that providing users cost reflective signals, such as a locational element within charges, is an effective method for the industry to achieve value for end consumers, but one that must be weighed in the balance with other licence objectives. For example, cost reflectivity may also lead to short term price instability, which may undermine wider investment in supply and hence competition. Therefore TransmiT should consider how cost reflectivity can best be applied whilst taking account of these competing priorities.

Beyond the question of cost reflectivity, we recognise that as an industry we now face a period of unprecedented change. As such, the existing processes and methodologies will need to evolve, in both electricity and gas, and in both transmission and distribution. Likely areas for significant development include;

- sharing and flexibility of network capacity
- greater market interaction with the rest of Europe
- more flexible and active network technologies
- changing investment drivers

TransmiT should consider whether these developments can be progressed through industry process or require systematic change as part of a Significant Code Review (SCR). In our view these changes could largely be progressed through the appropriate existing industry change processes once the objectives and principles have been confirmed through Project TransmiT.

In summary, TransmiT should consider:

- The objectives in the transmission licences that relate to charging and the relative balance and priority of each of these objectives.
- Specific areas in need of change to future proof the regime, including wider integration and interaction of European regulations into the GB regime
- Once these objectives and priorities are established, Transmit should conclude how to progress with more detailed developments, whether through SCR or regular industry change processes.

If you wish to discuss any of these issues or comments further, or have any other queries regarding this response, please contact either myself or Mark Ripley on 01926 654928, e-mail mark.g.ripley@uk.ngrid.com.

Yours sincerely

Alison Kay
Commercial Director UK Transmission

Annex 1 - Response to Call for Evidence Questions

Charging

Are the objectives, scope and priorities of TransmiT appropriate?

National Grid understands and agrees that the aim of Project TransmiT is to ensure that the industry has in place arrangements that facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future customers. Initially, we believe that this should be through reconsideration of the continued applicability of the high level charging principles and objectives. To that end, it would be helpful if further clarity could be provided as to how competing objectives should be prioritised between:

- Continuing to minimise cost and risk to consumers; and
- The need to achieve the 2020 environmental targets; and
- Against the above background facilitating the broader investment required within the industry (perhaps at greater cost and risk to consumers)

Given the role of networks in facilitating connections and wider investment, and the relatively small proportion of costs of networks, it is possible that on occasion wider investment and competition can be better facilitated by placing additional cost and risk on networks, as has been seen under the Connect and Manage transmission access regime.

The scope of the review is described as including both electricity and gas arrangements, covering charging, related connection issues, integration within Europe and also other market and regulatory developments. Whilst we broadly agree with this scope, we believe that the overriding priority should be the establishment of clear, predictable and enduring objectives and principles that facilitate investment in a way which underpins the potential for meeting 2020 targets. We understand that some parties have indicated that the existing electricity charging and connection arrangements may be a barrier to achieving these targets. Whilst we do not agree with this perception (and even if it were to be the case, there are a number of other issues which may be affecting connection rates), it is entirely right to review the current objectives and arrangements to understand if they need to be refined to enhance the conditions under which the 2020 targets can be met.

Whilst the current gas arrangements should form part of a holistic review, one of the areas to prioritise (although not at the exclusion of other issues) may be the implications on gas of a changing electricity world. If gas represents the primary back-up fuel to renewable electricity generation, then changes to electricity arrangements may have consequential impacts for gas. As a result, current gas charging arrangements may not appropriately facilitate security of supply in the event that demand becomes more variable and gas load factor reduces. There may also be broader consequences from changing the relative locational signals in gas and electricity.

We do not believe Carbon Capture and Storage (CCS) should be included within Project TransmiT as it is not currently part of the regulated portfolio. The pipelines anticipated to facilitate CCS do not represent meshed networks with multi user arrangements and hence there are few parallels with gas and electricity transmission with their multi entry-exit based access and charging arrangements.

Project TransmiT objectives also need to be viewed alongside developments and objectives in other areas. These should include the transmission revenue control, the wholesale Energy Market Review, and the integrated European market. There would also be merit in reviewing the objectives against the relevant EU legislation to provide further confidence in their robustness. We believe that this will be required in any event as a consequence of the introduction of the 3rd Package.

It would also appear sensible to identify certain areas of TransmiT that could be progressed in parallel to ensure a timely conclusion. Adopting this parallel processing maximises the opportunity for meeting the wider goals of the industry and Government. In particular, we would suggest that reviews of pre-commissioning user commitment and consistency with Europe could be taken forward as separate, more immediate, work streams.

Within the GB arrangements the charging objectives and methodologies are only one element of an overall industry framework. An examination of the incentives on industry parties should also consider the interaction with other policy support mechanisms (ROCs, FITs, etc.). In principle, National Grid believes that such support mechanisms should be outwith the core charging methodology so that they can be directly targeted at their intended beneficiaries. This ensures a fair and competitive market for all participants, whilst avoiding unintended consequences.

Are the current charging principles fit for purpose given the new and emerging challenges?

The current charging principles are: the facilitation of competition, cost reflectivity, taking account of developments in the transmission business, and non-discrimination. Historically these principles have worked well, and we believe that they remain relevant to meet the challenges the energy sector faces over the next decade. However, given the scale of the challenges ahead, we believe it is pertinent to review these principles and the relative priority given to each one of them.

The current charging principles differ slightly from the criteria that Ofgem uses to assess proposed changes, i.e. there is no objective to consider sustainability. Alignment of assessment criteria will ensure greater consistency between code development work undertaken by National Grid, industry assessment of changes, panel recommendations and Authority decisions. Therefore, there is a strong case for including the Authority’s wider objectives more formally in the code assessment criteria.

It also needs to be recognised that the GB power industry is increasingly part of an integrated European market, and is therefore required to comply with various EU rules. Project TransmiT provides an opportunity to ensure alignment of both the GB transmission charging principles with relevant EU requirements.

Are the current approaches consistent with the principles currently in place?

In our view the current approaches are consistent with the principles currently in place. The methodologies employed by National Grid have been regularly assessed in accordance with the relevant licences and approved by the Authority under the Gas and Electricity Acts. There is evidence, both in reports to the Authority and regulatory impact assessments, that National Grid’s current approach has been deemed to be both consistent with the existing charging principles and is applied consistently. It is also recognised that approaches need to evolve against changing industry needs and National Grid has frequently engaged with industry on modifications to the charging methodologies to facilitate such changes. Examples of this include discussions within the existing gas charging arena on exit price stability (are the modelled supply and demand flows appropriate) and the balance between commodity and capacity charges.

Notwithstanding the above, the industry is undergoing a period of radical change and therefore the methodologies must continue to evolve to ensure that they remain suitable.

Do the current charging arrangements deliver value for money for energy consumers?

In our view the existing arrangements have delivered value for money but it is timely to assess whether they will continue to do so.

The efficiencies produced by the current arrangements rely on transparency and predictability of pricing and the accuracy of locational signals. However, the effectiveness of locational signals rests on their ability to influence actual siting decisions. It can be seen from recent connection activity that power stations do respond to charging signals, and such decisions deliver real benefits to the end consumer. For example, where a CCGT decides to connect will be a balance between increased electricity or gas transmission, giving consumers confidence that the overall costs they pay (including energy) are likely to be lower as a result of these signals.

In the case of renewable generation, we understand that the choice of where to locate is more limited, but believe that the same basic principles still hold. The exploitation of wind power in more remote areas has the benefit of greater availability but at higher network infrastructure costs. These locations can be assessed against alternative renewable sites with lower output but also lower network costs.

However, a counter view could be advanced if, for example, the scarcity of renewable resource is such that all resources need to be exploited and connected to the grid regardless of location. The lack of locational choice in such a scenario would then mean that the benefit of locational signals would be undermined or even redundant. However, the level of existing and prospective renewable projects suggests that there is not currently such a scarcity of resource potential. Hence locational signals continue to have a significant role to play in delivering efficient outcomes. In fact, our understanding is that the principal factor that would limit the exploitation of renewable resources in areas closer to demand, and thereby force more expensive network outcomes, is public acceptance and planning. Whilst we agree that developers face major challenges with consents, we are currently observing a good level of potential projects being considered, and it would be for developers to highlight any underlying issues that are not readily apparent to us as a network owner.

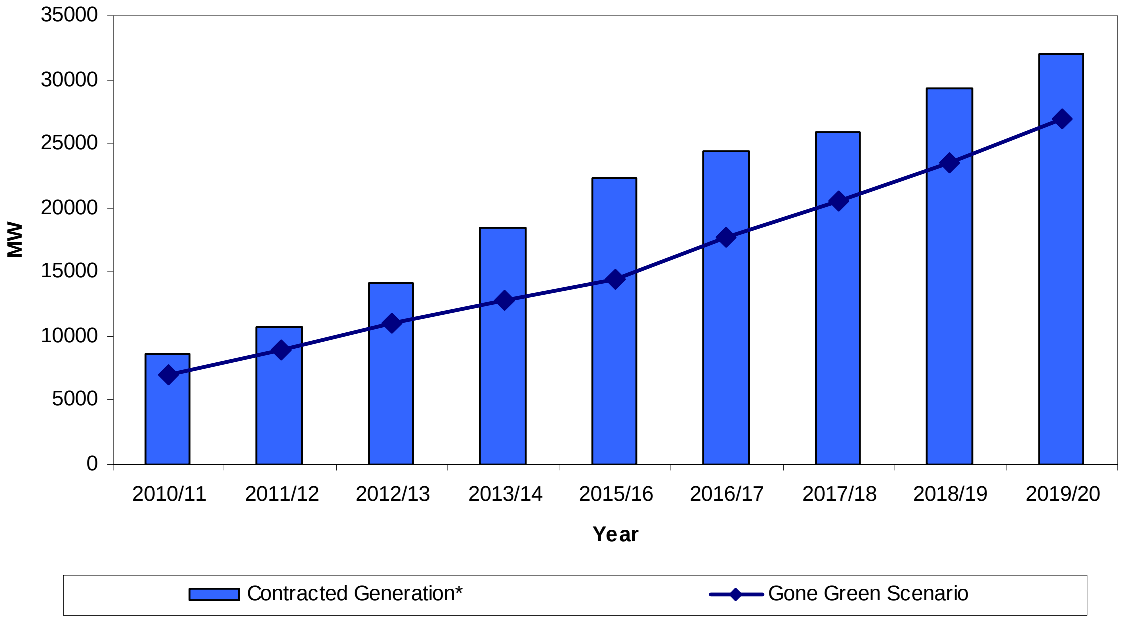
Overall, it is important to have processes in place that allow market participants and investors to effectively manage risk in the best interests of the end consumer. In most cases a competitive market is likely to manage risk more effectively than a centrally administered solution. In the case of a shared resource such as the transmission system it is inevitable that there needs to be some form of central management. However, the efficiency of this central management is reliant on information from the market. Alongside capacity booking mechanisms and user commitment, the charging principles play an important role. Modifications to the principles that remove information will have a negative impact on the efficiency of the central system unless they are replaced by other risk management mechanisms, for example incentives under revenue control arrangements.

Do the current charging arrangements facilitate connection of low carbon generation?

The current electricity charging methodologies developed under the existing principles have resulted in connection applications that currently exceed the level required to achieve the 2020 targets for renewable generation. This is indicated in the chart below (source November TNQCU), which shows approximately 30GW of contracted renewable generation connecting by 2020.

Whilst only an indicator of future potential connections, this data highlights that projects (which are widely spread through GB albeit with higher concentrations in Scotland) are prepared to site in higher cost areas with two caveats:

- The majority of these projects are not fully consented or financed and we would expect to see significant attrition as these projects go through these processes.
- Figures for locational charges were not finalised (for example in the Scottish islands) at the time projects applied for connection.



At the same time, the gas charging methodology developed under the existing proposals has not deterred connection applications for both new power generation and storage.

The current electricity charging arrangements are not technology specific, and are consistently applied across all generator types on a capacity basis. There are a number of charging issues for both existing and prospective generators which are common whether they are low carbon or not. This would include transparency and simplicity of charging, such that cost reflectivity is improved and competition stimulated. Certainty of revenue streams is also critical for both existing users and prospective developers. Parties require clear, understandable and consistent forward signals at both a GB and European market level. From a charging perspective it is therefore vital that there is a level of stability and predictability to TNUoS charges.

Despite the above, it is recognised that there are significant differences between the business drivers for renewable generation technologies, and conventional generation. Given the intermittency of much renewable generation, it is debatable whether the current charging arrangements are optimal for facilitating the connection of low carbon generation. To this end, National Grid has recently consulted on the potential for specific charges for different access products. Initially this has been for wind as they are demonstrably different given the inherent restriction on their fuel source. For generation that reacts to market signals and can generally control their output then their anticipated operating regime is much less clear. Even nuclear power stations will shape their availability profile in reaction to market prices e.g. bring forward maintenance. In order to facilitate security of supply we will be further investigating this area.

Finally it should be noted that previous studies have examined the impact of reducing the locational signals for renewable generation[1]. The main conclusion of these studies is that given the inherent profitability of locating generation in remote areas (where TNUoS is likely to be higher) a reduction in TNUoS does not create a significant increase in connection volume.

[1] Impact of GB Transmission Charging on Renewable Electricity Generation - report to the Department for Trade and Industry

Are there any particular charging issues to be prioritised ?

As highlighted in the response to previous questions, we believe that it is correct to assess and confirm the wider charging principles and objectives in the first instance. Only when these are understood, should consideration of particular charging issues be made.

Priority should be given to charging issues that are believed to specifically assist in the overall objective of Project TransmiT, i.e. facilitating the move to a low carbon energy sector. These should include issues of particular pertinence to renewable energy sources such as sharing of network capacity to reflect increased volumes of variable generation, island charging, and treatment of distributed generation.

Additionally there are a number of broader charging issues that are worthy of consideration, whether this be as part of Project TransmiT or separate charging proposals. We have detailed some of these issues below, but this list is not exhaustive. As previously mentioned, National Grid considers it appropriate for Project TransmiT to initially focus on the continued suitability of the overall charging principles to meet the overall objective of the review.

1. *Network Technology Changes.* The transmission systems will need to be able to anticipate and manage new and active network technologies including distribution systems.

2. *Offshore Electricity.* There are significant savings in developing a more integrated approach to offshore electricity transmission.

3. *Greater market interaction with Europe.* In respect of the European market, signals need to be consistent across all participants to ensure effective competition and a sustainable and secure long term energy position for GB.

4. *Gas Security of Supply.* Gas charging arrangements should appropriately incentivise security of supply through the development of supply diversity, including new gas storage projects, and network flexibility. The potential need for greater network flexibility is largely driven by;

- Supply diversity including new storage and interconnection projects; and
- The potential for rapid changes in supply and demand patterns and flow directions driven by
  - new supply and storage projects
  - the impact of renewable electricity on gas generation; and
- The on going support for conventional flow profiling such as the distribution network demand profiles.

5. *Gas Commodity Charges.* High entry commodity charges have been identified as being driven, in part, by the users' ability to profile capacity procurement to meet flows. As gas demand becomes more variable then this situation may be exacerbated.

Finally, we understand that users are particularly interested in certainty and therefore a review of fixed locational electricity charges may be appropriate. The principle of long term fixed charges is not tied to TransmiT although the basis of the calculation of the locational charge is clearly within scope. It should be noted that this issue is directly related to user commitment. The balancing of the issues of gas capacity price stability and cost reflectivity is an area of continual review and it is expected that this will continue with the changing supply and demand patterns.

Connections

Are the connection objectives correct?

There have been some changes to electricity connection arrangements as a result of DECC intervention on TAR. The Connect and Manage regime is a significant move forward and will help facilitate the timely move to a low carbon energy sector. Whilst there are concerns about potential operational costs, these can be minimised through incentive arrangements, both on licensees and users.

Gas connections are charged on a cost pass through basis, and a connection can be facilitated independently of deep system reinforcement. Hence the issues are associated with connection timing rather than connection charging.

We remain committed to improving the gas and electricity connection processes, and are currently looking at ways to achieve this. For example, in electricity, we believe that additional measures can be taken to reduce the level of securities required at the pre-construction stage. We have already introduced a reduced securities regime, demonstrating that such a regime placed minimal risk on consumers. A clear prioritisation of objectives and examination of the appropriate balance of risk between consumers, developers and networks companies could help provide the basis for further work in this area to further reduce developer costs, facilitate investment in low carbon generation and also facilitate competition.

Are there practical problems hampering connection to the network?

In National Grid's experience the main practical issue hampering the connection to transmission systems is the planning consents process. Whilst this is outside the scope of Project TransmiT, we would hope that this review promotes the planning need case. To support this TransmiT should be completed as soon as possible with clear unambiguous conclusions that are consistent with the wider framework.

Beyond this there are opportunities to refine the contractual structure to ensure it provides clarity of investment decision and timing for developers and network companies alike. We believe these changes can be progressed through normal industry processes.

Do existing connection arrangements ensure fair treatment of system users?

The issue of fairness is key to underpinning a competitive market and competition between system users. Where a particular class of user has different arrangements this needs to be objectively justified. Given the number of user classes that both exist, and could arise, in our view TransmiT should assess its recommendations against fairness and impacts on each type of user.

Are there particular connection issues that should be prioritised?

For electricity connections, consideration should be given to prioritising pre-commissioning user commitment, in particular for islands and offshore. It should be noted that National Grid currently has an interim arrangement for wider final sums and we believe that it would be beneficial to keep this arrangement during Project TransmiT.

We would welcome views on other areas that can be prioritised.

Annex 2 - Technical Annex

This annex provides some generic examples to support the views present in our main response.

1) An illustration of the impact of wider locational TNUoS on renewable generation

The existing principles in NGET's Transmission Licence, upon which the TNUoS methodology is based, serve to minimise the overall generation and transmission system costs to that which an efficient central planning body would incur, i.e. pre-privatisation. A cost reflective use of system tariff should provide an independent generation company with the necessary information and incentive to take the cost of transmission into account when making a decision on where to site their plant, i.e. internalise the costs. Theoretically, the benefit to this approach is that it allows for the optimisation of the overall cost of energy delivery for the benefit of the consumer.

Not a great deal of information is available publicly upon which to corroborate the relative economics of locating a project in one area versus another. National Grid understands that many factors are involved in the decision on where to site a project. In order to better understand the effect of TNUoS liabilities, relative to that of resource availability, we have undertaken some simple analysis.

In assessing the effect of resource availability a Monte Carlo simulation was undertaken on a Weibull distribution with a shape factor of 2 (Illustrated in Figure A2.2) for various mean wind speeds to estimate the actual wind speed for each hour of the year. Subsequently, the kW output for each hour was multiplied by the power curve (illustrated in Figure A2.1) of a typical 1.8MW wind turbine. This resulted in a representative value of the total kWh power output expected from a 1.8MW turbine across a year for a given mean wind speed. The process was repeated for mean wind speeds of 5, 6, 7 and 8 m/s.

Figure A2.1 – Typical Turbine Power Curve

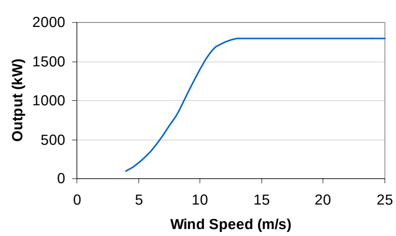
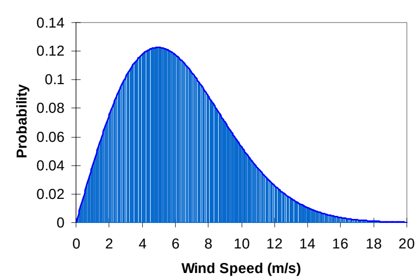


Figure A2.2 – Example Weibull Distribution



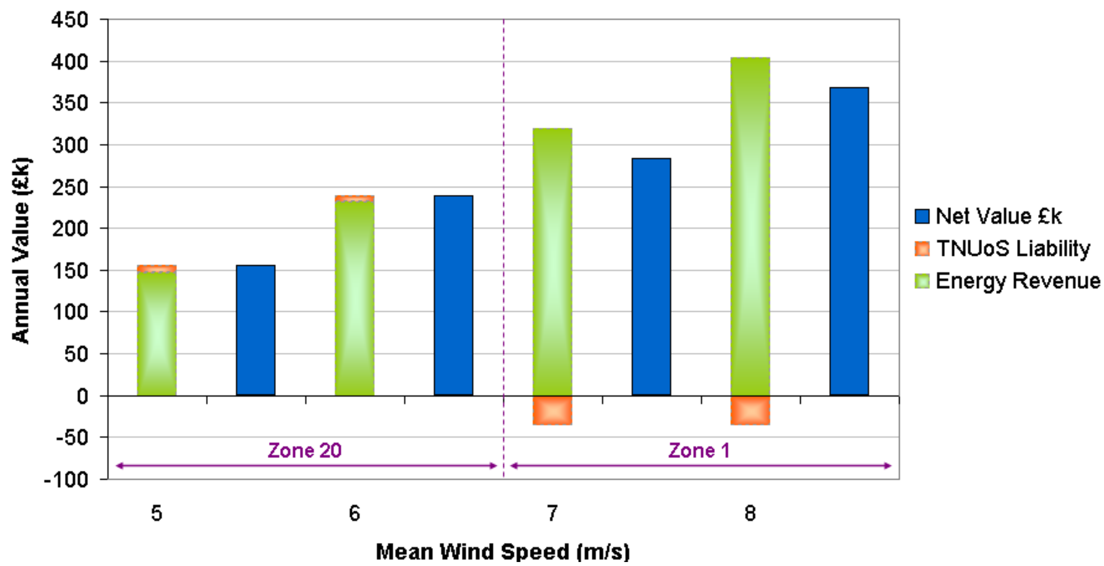
The representative kWh annual output of the wind turbine can then be multiplied by a typical energy price (taking into account the value of Renewable Obligation Certificates - ROCs) in order to ascertain the potential revenue for areas with different wind speeds. For the purposes of this analysis a conservative value of £70/MWh was used (comprised of a £25/MWh brown energy price and £45/MWh ROC value).

The value of energy for areas with different average mean annual wind speeds relative to the annual wider locational TNUoS liability for the typical 1.8MW turbine in the North of Scotland (TNUoS Zone 1) and the South West of England (TNUoS Zone 20) can then be illustrated using 2010/11 TNUoS tariffs. For the purposes of this illustration it is assumed that sites with mean wind speeds of between 5 – 6 m/s are available for development in the South West and sites with mean wind speeds of between 7 – 8 m/s are available for development in the

North of Scotland. Through including representative locational differentials in wind speed, revenue also varies by location as it is based on volume of output. To the extent that the output is variable by location then the overall income, including ROCs, also becomes variable by location.

All other costs being equal, Figure A2.3 illustrates that the difference in annual wider locational TNUoS liability between generation TNUoS zone 1 and 20 (with existing tariffs of ~£20/kW and ~ -£7/kW respectively) is very small in comparison to the increase in revenue resulting from the availability of increased mean wind speed between these two zones. Clearly, as TNUoS is a capacity based charge, this effect is amplified for less conservative energy price assumptions.

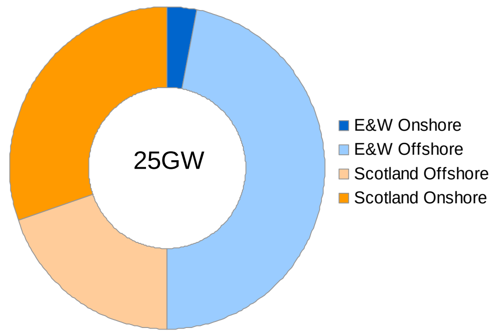
Figure A2.3 – Representative Relative Economics Between TNUoS Zones (Typical 1.8MW Wind Turbine)



The effect of the local circuit and local substation elements of TNUoS are not locational in nature, but instead are project specific and therefore not illustrated. Nevertheless we recognise that the impact of these local elements can be significant for offshore and island users, where expensive sub-sea cables are included. The ROC mechanism has been amended to reflect additional cost offshore and the Section 185 powers in the Energy Act could be used to address these specific issues.

In addition to the above example, the geographical disposition of the 25GW of wind generation with signed transmission connection agreements in Great Britain, illustrated in Figure A2.4, indicates that the principle of cost reflectivity (at its current level) may not be prohibiting the development of renewable generation.

Figure A2.4 – Contracted Wind Generation



The above figure illustrates that approximately 50% of currently contracted onshore and offshore wind generation capacity is located in England & Wales and 50% is located in Scotland. There is of course a difference between connected and contracted, and we look forward to reviewing any evidence of the relative profitability of projects from generation developers.

In summary, the locational benefit of higher wind speed and the resulting increase in revenue appears to outweigh the increased cost of transmission for the majority of generators. When choosing a site generation developers weigh up the impacts of these and other locationally varying costs on the profitability of their projects in conjunction with environmental impact and consenting issues. We recognise that there are specific issues on Islands and Offshore, although these could be addressed outwith the TNUoS methodology.

2) An indication of the benefits cost-reflectivity has provided to date.

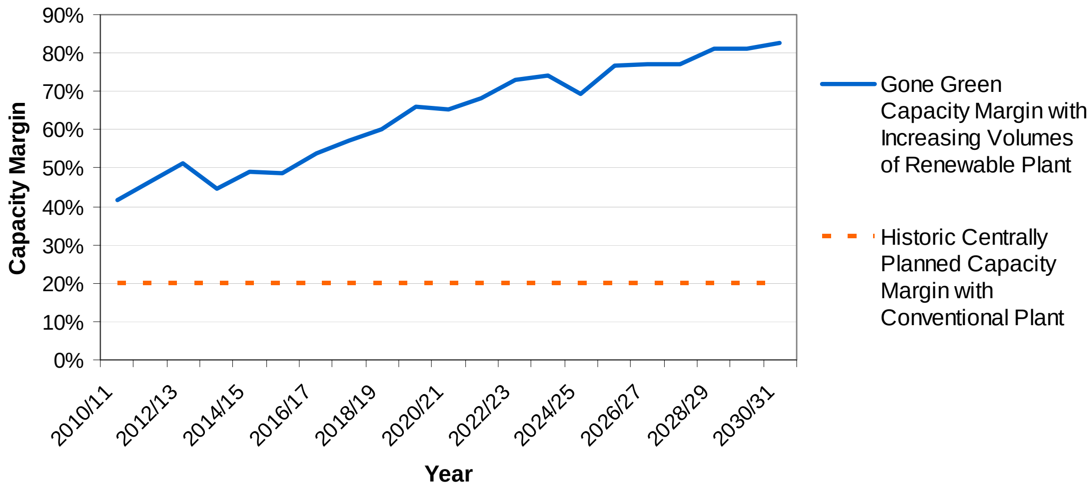
In an attempt to illustrate the benefit of avoided transmission network cost associated with the existence of cost-reflective locational transmission tariffs, National Grid has undertaken some simple analysis. The basis of this analysis is that the majority of locationally varying costs are likely to indicate that a generation connection would be more economic in the north as opposed to the south of Great Britain and that a generator may therefore choose to locate in the north, were it not for the locational electricity transmission use of system charges.

This analysis estimates the impact on network cost if two gas fired generation stations, totalling approximately 1800MW in capacity, in the south of Great Britain had instead chosen to locate in the north. An exact assessment of the impact of such a change in generation location is difficult to achieve due to, amongst other things, the ‘lumpy’ nature of transmission investment. However, National Grid estimates that the additional cost of network reinforcement would amount to between ~ £650m - £1550m if the two stations modelled had located further north due to a lack of locational signal.

3) The need for additional information to reflect increased sharing of network capacity into commercial arrangements, including charging.

The percentage of installed generation capacity over and above the peak demand level in National Grid’s *Gone Green* scenario, illustrated below, demonstrates the challenge facing existing charging and access arrangements that are predicated on an electricity system comprised predominately of conventional generators with high load factors.

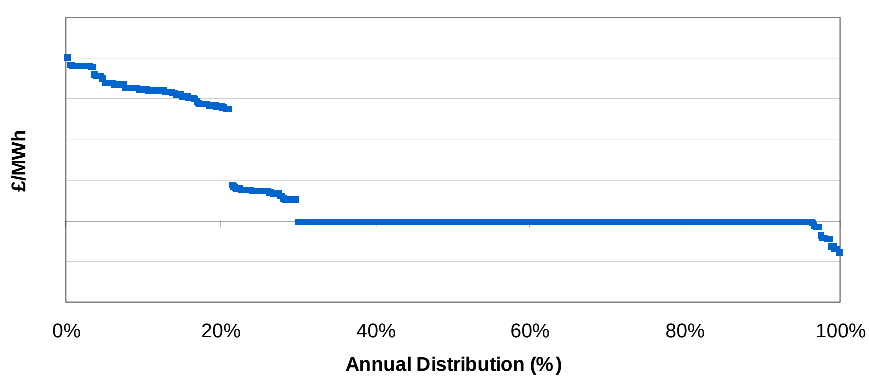
Figure A2.5 – Gone Green Generation Capacity Margin Over Peak Demand



Prior to the drive to connect more variable renewable generation (which has a lower load factor) the market delivered a plant margin of around 20%. This is broadly consistent to that invested for under the historic central planning environment. However, as more renewable generators connect to the network the total installed capacity of generation will need to increase in order to ensure the continuous supply of electricity demand. The result of this increase in total installed capacity is that generators will increasingly share network capacity as different technologies counter correlate at different times.

Under this scenario the driver for network investments moves away from the historically robust system peak security driven requirement to more of a year round cost benefit analysis. As a result, transmission investments are primarily made to avoid the expected constraint costs. The illustrative annual distribution of constraint costs on a relatively heavily loaded network boundary, shown in Figure A2.6, illustrates that for 70% of the year spare capacity exists across the boundary, such that a generator should be able to utilise this capacity without triggering additional transmission costs. Conversely, a generator utilising capacity for the other 30% of the year would trigger significant additional costs.

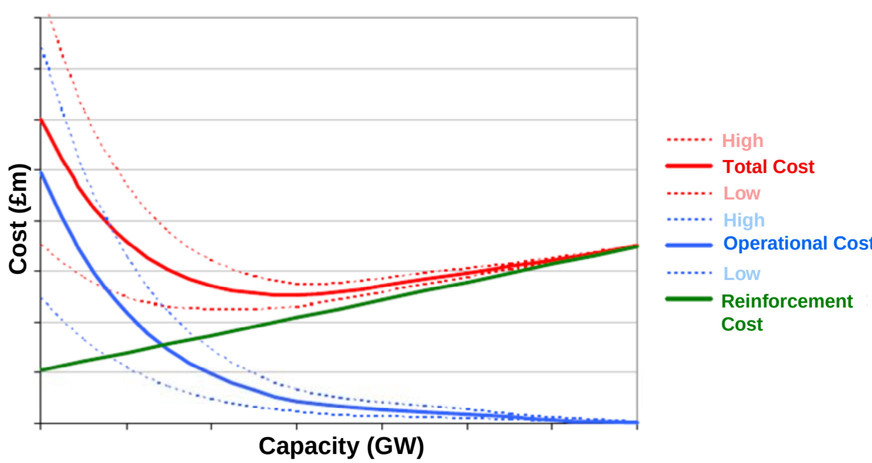
Figure A2.6 – Illustrative Distribution of Constraint Costs on a Representative Network Boundary



The current commercial arrangements do lack network 'time of use' information and it is therefore difficult, from a transmission perspective, to reflect the changing nature of network usage that results from the change in generation characteristics. As the amount of renewable generation connected increases (along with the required margin of generation capacity over demand) the level of central assumptions in planning increase. In order to continue to ensure that transmission costs incurred are in the best interests of the end consumer, incentives for the increased provision of information may be necessary. With this we recognise that future forecasting of market conditions is extremely difficult for any individual party.

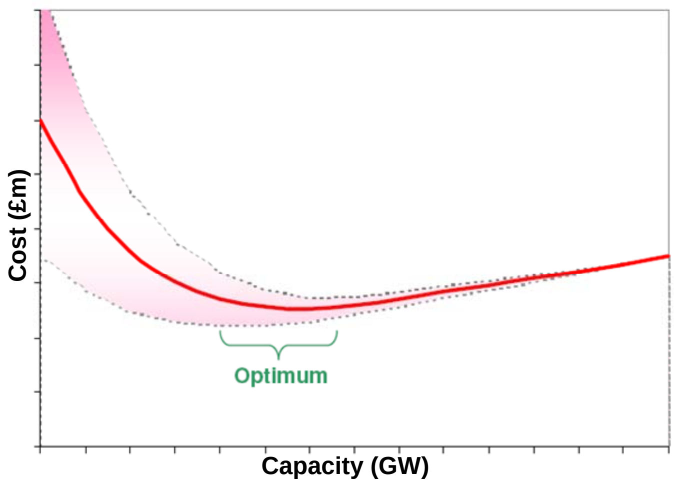
Analysis recently presented in the SQSS review combining operational costs versus network reinforcement costs on a representative network boundary, recreated for illustrative purposes in Figure A2.7 and A2.8 below, indicates the potential risks to end consumers of the total costs of over- and under-investment in network capacity. This demonstrates that the risks are asymmetric, with the incremental cost and potential range of outcomes for under-investment being far more extreme and costly. Including flexibility within the transmission arrangements serves to reduce these risks and also reduces the burden of information on market participants. In addition, this highlights the interaction of market information provision with the Transmission Price Control Review.

Figure A2.7 – Combination of Operational and Network Reinforcement Costs



The reinforcement costs, illustrated in green, are relatively simple to forecast with minimal uncertainty. The operational costs, in blue, can vary significantly for a decreasing network boundary capacity due to the lack of information to facilitate optimal sharing of network capacity, as outlined above. The combined costs, in red, are optimum at the minima of the total cost curve. However, the risk of deviation from forecast cost assumptions increases significantly as network capacity moves to below the optimal level, as shown in Figure A2.8, below.

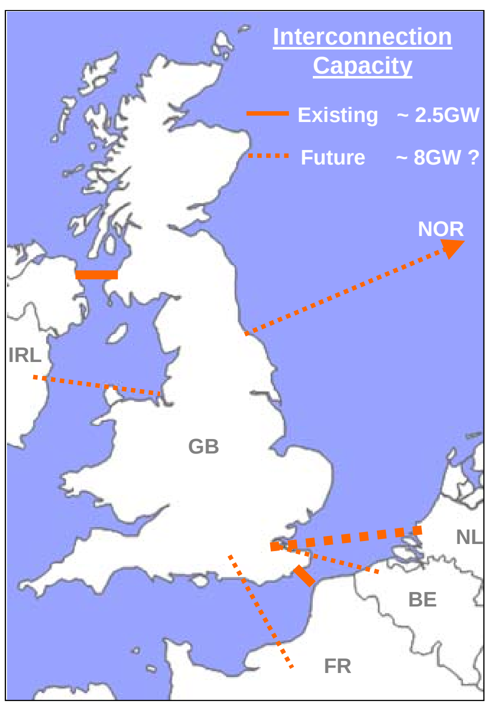
Figure A2.8 – Increased Total Transmission Cost Uncertainty for Under Investment in Capacity



4) Evidence of requirement to consider alignment of commercial arrangements with neighbouring European countries

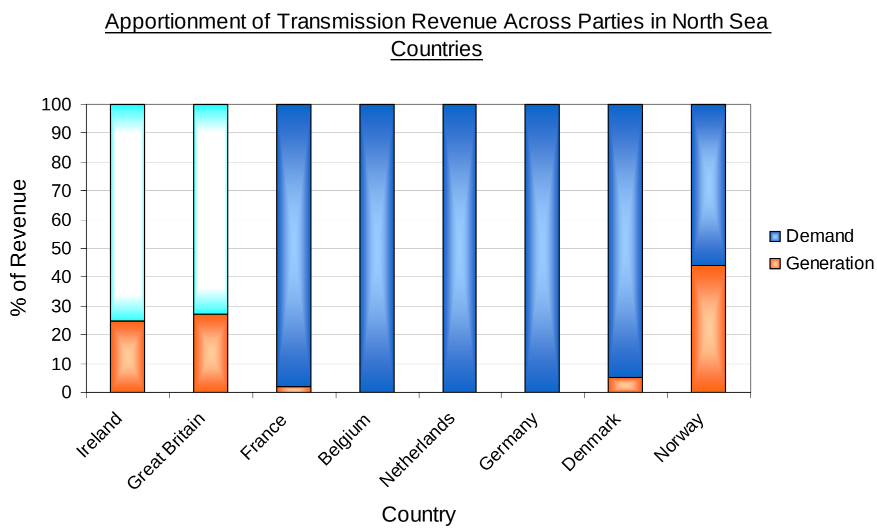
The future holds a significant increase in interconnection capacity with adjacent markets. The extent of this future interconnection, a potential 320% increase, is illustrated in Figure A2.9.

Figure A2.9 – Existing and Future Potential Interconnection Capacity



This further integration entails access to a wider electricity market which should provide benefits to Great Britain as a whole. In order to ensure that parties participating in this wider market have a level playing field for competition, and thus maximise the potential benefit, commercial arrangements should be compatible as far as reasonable practicable.

Figure A2.10 – Difference in Charging Arrangements Across Adjacent EU Markets

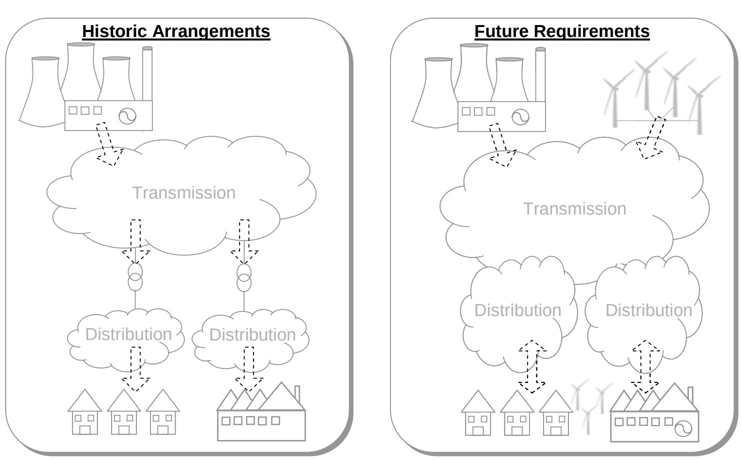


It is difficult to directly compare numbers across markets due to the variation in detailed arrangements (deep vs. shallow charging, etc.) in different regions. However, Figure A2.10 illustrates the difference between the charging arrangements in Great Britain and adjacent markets in terms of the amount of revenue collected for transmission owner activities from both generation and demand. This is the stated net revenue collection position and so does not include any signals applied in individual countries, either short term or long term.

5) The need for increased consistency across transmission and distribution arrangements

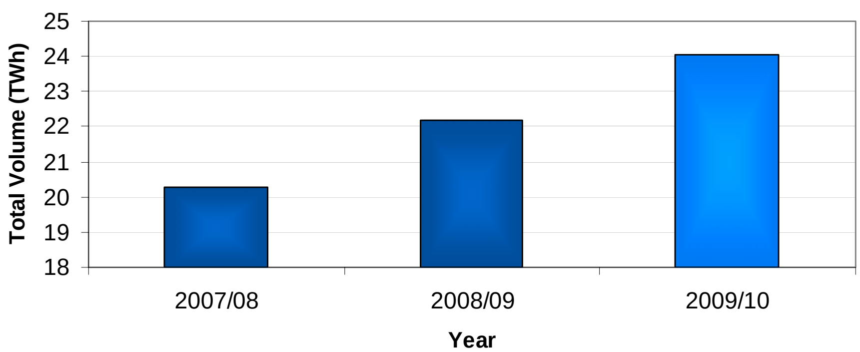
The proportion of generation connected to the distribution network (embedded generation) continues to increase. Government incentives such as Feed-in-Tariffs have been put in place to further encourage embedded generation for the security of supply and economic benefits that they can provide. The contrast between existing arrangements and future arrangements in relation flows at the interface between distribution and transmission networks is shown in Figure A2.11, below.

Figure A2.11 – The Changing Nature of Framework Requirement



The current arrangements are predicated on the historical, relatively distinct, roles of transmission and distribution. As the level of embedded generation increases, as illustrated by the half hourly metered Supplier Volume Allocated export volumes in Figure A2.12, commercial arrangements also need to evolve in order to ensure that market participants have access to a level playing field for competition, whilst recognising the different characteristics of the networks involved.

Figure A2.12 – Total HH SVA Export Volume of Embedded Generation

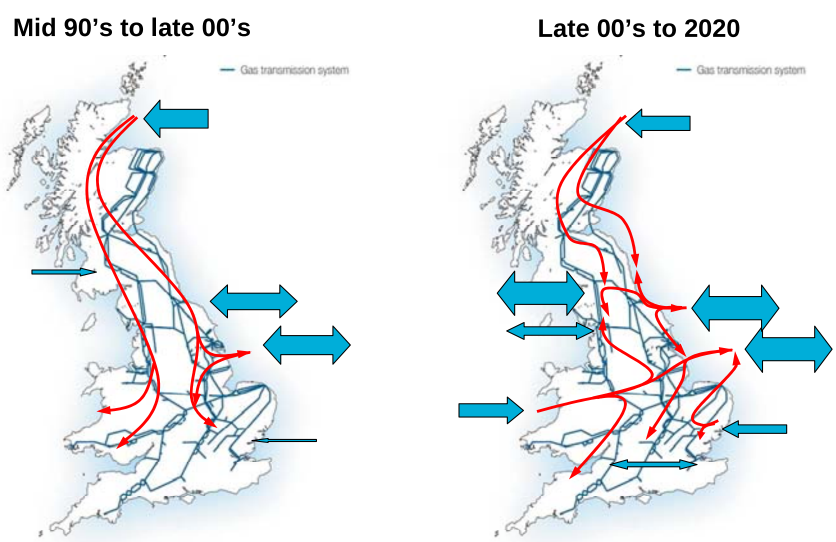


Changes to address this issue may necessitate significant alterations that reach across the entire spectrum of charging and connection arrangements.

6) The changing nature of gas flows on the transmission network

The changing nature of gas flows on the transmission network are characterised by increased diversity and geographical location of supply from storage and interconnectors, as illustrated in Figure A2.13, as well as the potential for rapid changes in supply and demand patterns arising from the impact of renewable generation on gas generation.

Figure A2.13 – Illustrative Changes to Gas Transmission Network Supply



In addition, given their interaction, any changes made to the electricity arrangements should be checked against those in gas to ensure that both remain fit for purpose.