A framework for considering reforms to how generators gain access to the GB electricity transmission system

A report by the Access Reform Options Development Group

April 2006

Summary

The transmission system transfers electricity in bulk at high voltage from generators to large industrial users and to local distribution networks. There is a single transmission system for the whole of GB.

An efficient transmission network helps provide consumers with reliable energy supplies. However, consumers also pay for the costs of the network. As such, it is important to ensure that the owners of the networks neither under nor over invest in the system.

Generators compete to sell their energy to suppliers and in turn suppliers compete to sell the energy to end customers. The price paid by consumers for their energy will, to an extent, be determined by the amount of competition in generation; with more competition likely to lead to lower prices. Therefore, creating conditions which allow entry to the market can be expected to benefit customers.

This document sets out the findings of a joint industry group, chaired by Ofgem, which has considered options for how arrangements for generators connecting to and using the transmission system might be changed. This work was prompted by perceived difficulties with the current arrangements in the context of a large number of new generators seeking connection to the network and the difficulties this presents for network investment.

The Group has sought to present the options for change in a comprehensive and systematic manner. The options cover broad areas. First, the financial security required from new users prior to connecting to the network and being granted rights to use the network. Second, the range of access products that might be released to network users (or exchanged between network users) in the short and long term under different circumstances – and the process through which network users buy such rights.

The purpose of the report is to stimulate debate and help parties develop specific proposals for change, if they consider that the current arrangements could be improved upon, in the context of understanding how the various pieces might fit together. Ofgem would welcome views on this report. All responses will be published on the Ofgem website.

Deadline for response

Wednesday 7th June 2006 to mark.copley@ofgem.gov.uk.

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1. Introduction

1.1 This chapter provides a brief summary of the current arrangements for network users connecting to and using the electricity transmission system. It sets out the issues and perceived difficulties with the current arrangements. It also describes why the ARODG industry workgroup was set up by Ofgem, and how it has operated.

Existing arrangements

1.2 The current system of acquiring transmission capacity is based around the concept of first-come-first-served. Any prospective generator wishing to connect to and use the network must apply to National Grid and wait until specified additional works on the network have been completed by the relevant Transmission companies. Generators who have already been through this process have an enduring right to use the network, subject to a rolling annual obligation to pay transmission charges. Existing users can hand back their rights at any time, and in return the obligation to pay transmission charges falls away with effect from the following April.

1.3 While a new generator is waiting to receive its access rights it is required to provide financial security against some of the works identified as being necessary to ensure that the system complies with the relevant planning standards. There are complex rules determining how exactly these works are identified. It depends on technical standards, when the application was made, and whether any of the works are shared with other applicants. The sharing of works between users can change over time. The financial security (called 'Final Sums Liability', 'FSL') can also therefore change over time.

1.4 The purpose of FSL is to insure against the risk of unnecessary investment if the generator does not subsequently connect to the network. Once the generator is connected and starts paying for use of the network, FSL falls away.

1.5 Generators who are connected to the network can supplement their existing rights (if any) by applying for shorter term (and, in some instances, less certain) access rights. These products are only released by National Grid if it expects with certainty that the network will be physically capable of accommodating the extra rights alongside all the other rights already allocated without increasing system operation or congestion costs.

1.6 The Connection and Use of System Code (CUSC) sets out the standard commercial terms between generators (and other network users) and National Grid. This is supplemented by a number of bilateral agreements, including construction agreements, where works are required to provide a user's access rights. The CUSC uses the concepts of Connection Entry Capacity (CEC) and Transmission Entry Capacity (TEC). CEC is the capability of a user's connection, while TEC reflects the capability of the wider transmission system and defines the user's access rights. A value for CEC and TEC are set bilaterally for each generator. TEC cannot exceed CEC.

Issues with the current access arrangements

1.7 A number of industry parties have raised concerns about how the current arrangements are operating. This is in the context of an unprecedented number of applications from prospective generators, in particular (but not exclusively) wind-powered generation projects in Scotland.

1.8 To illustrate, over 100 applications totalling around 14 GW of generating capacity are currently seeking connection in Scotland. Today, bulk electricity flows are from the north of GB (where there is a surplus of generation) to the south of GB (where there is a surplus of demand). Increasing the surplus of generation in the north still further would require significant investment in the network. This involves major infrastructure projects, which take time to deliver (and in many cases require consents[1] being gained before they can be constructed). There is, therefore, no quick and easy solution to the queue.

1.9 In all likelihood, only a proportion of the projects currently in the queue will actually connect to the network. The most significant factor is likely to be whether the generator obtains consent. The large majority of projects in the queue do not yet have the necessary consents.

1.10 There are two broad areas of concern that have been raised relating to how the access arrangements operate in the current environment:

- First, the transmission companies need to plan investment in the network. In the current climate, it is far from clear how much generation will connect, how much investment is needed, and where it should be focused. It would cost billions and take many years to upgrade the network to cope with all possible new applications – and a significant amount of the investment in extra transmission might prove to be unnecessary (with the associated large economic and environmental costs) if, as expected, only a proportion of the current queue actually connects. On the other hand, an insufficient volume of investment may also create problems. An issue for the access arrangements is how and, critically, when information is made available on where investment is needed.

- Second, the impact on competition and market entry of the current FSL arrangements. Because future investment plans are very uncertain (and can change as parties join or drop out of the queue), the security sums being required under the FSL method are, in some cases, proving to be large and volatile. While the principle of insuring against the risk of wasteful investment if the transmission companies invest and the generator does not connect would appear to remain valid, it also appears timely to review whether FSL in its current form (and as part of the overall package of arrangements) is the best way to do it.

[1] The process of obtaining consents for the construction of a new overhead line to serve, for example, a wind farm can essentially be broken down into two distinct areas. Consents to be obtained from the Secretary of State/ Planning authorities etc in relation to permission allowing a line to be built and secondly, and more practically, consents from landowners who will be effected by the construction of the new line.

1.11 In developing the options discussed in this document, the ARODG considered the allocation of risk. An amount of risk (for example the potential for assets to be stranded or system operation costs to increase) will always exist in the market and, regardless of where it falls, this risk will have a cost which will ultimately be paid for by consumers. However, these costs are likely to be lowest when risks are allocated to those best able to manage them. Risks can be allocated between new generators, existing system users and transmission licensees. A transfer of risk away from new connectees will, in the first instance, result in a greater amount of risk and level of cost to transmission companies, which may be expected to be passed through to consumers. In the diagrams in this document, this risk is collectively referred to as unsecured risk.

The Access Reform Options Development Group

1.12 The issues outlined above have been raised with Ofgem in a number of different ways, including in the context of the current review of the price controls of the transmission companies. In the light of these comments, and our wider duties, Ofgem decided that an industry workgroup could be useful in exploring the range of issues and how they interact, and to develop a framework for considering options for change. In part this reflected the fact that the access arrangements are currently defined across a range of industry codes and documents, and consideration of each possible element in isolation would necessarily only give a partial picture.

1.13 Ofgem set up the Access Reform Options Development Group (ARODG) to coordinate this work. The full ARODG terms of reference are available in Appendix 2.

1.14 The group was formed in response to an open invitation by Ofgem. There are 16 members, drawn from a range of industry parties. The group is chaired by Ofgem and Ofgem also provides the secretariat. The membership of the group is listed in Appendix 1.

1.15 The group met six times between February 2006 and April 2006. It sought to review, in a systematic and comprehensive way, the range of possible elements of change – and to identify effects and an initial view on potential implementation issues. Notes of all meetings and papers produced by the group are available from the Ofgem website. This report presents the collective findings of the group in the light of its terms of reference.

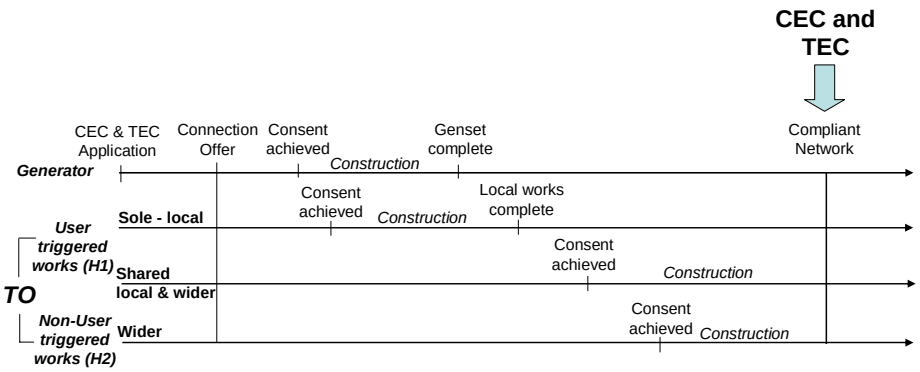
2. Constructing the options

2.1 Transmission access arrangements can be described collectively as the regulatory and commercial framework through which current and prospective users of the transmission network obtain a connection to, and rights to use, the network. The transmission access arrangements need to be reflected in, and be consistent with, the arrangements through which transmission companies are remunerated.

Existing arrangements

2.2 To aid understanding, the existing access arrangements are illustrated diagrammatically below.

Current Connection Timeline Milestones
- Diagram 1



nationalgrid

2.3 From the perspective of a generator or one of the parties which own infrastructure – the Transmission Operators (TO) - the process to request and provide a connection is as follows:

- A new generation project makes an application for connection (Connection Entry Capacity - CEC) to the transmission system and for use of the transmission system (Transmission Entry Capacity - TEC).

- Following application, the TO will consider the works that are required to deliver the transmission capacity and will provide an indicative connection date, subject to the acquisition of appropriate consents. The form of the offer will describe three categories of works; H1 sole, H1 shared and H2.

- H1 works are user triggered works. These are the works that are required to connect the new generator to the main interconnected transmission system, and the works which users are required to financially secure before commissioning. The purpose of the financial security is to indemnify the TO against the cost of works already completed in the event the power station project does not complete.

- H1 works are divided between those that are "local", and those that are shared with other users, and which may or may not be "local". The FSL amounts cover all H1 works – both local and shared.

- H2 works are those works upon which the new project is dependent before transmission access rights can be granted. These are works that have been secured by other parties or are background works that have been identified as necessary in previous reviews.

2.4 Once the offer has been signed, both the generators and TOs begin applying for planning permission and other consents. The timescales for these permissions are difficult to predict and, although Diagram 1 indicates a sequential process, permissions may arrive sooner or later relative to the other milestones, than the illustration suggests. It is true to say however, that in the generality of cases, consents for wider system works take longer than consents for local works because the projects are normally orders of magnitude larger. Following the granting of consents, construction begins and when all required works are complete, transmission access is made available to the generator.

2.5 The key point to note is that in most cases no transmission access is permitted until all the necessary consents and construction works have been completed.

The ARODG's assessment framework

2.6 The access regime is complex and in order to better structure the debate, ARODG adopted a framework that divides the regime into three main areas - described in Diagram 2. These areas are:

- Pre-commissioning securities.

- The status of rights between the time a power station is connected locally but the wider transmission network is insufficiently reinforced to accommodate this new generation and all existing generators – i.e. it is not compliant with the planning standards.

- The rights of users once the transmission network reinforcement to complete the connecting generator and all existing parties is complete and the network is complaint with the planning standards.

2.7 In each of the above "building blocks", there are key issues to be considered. For example:

- Whether the existing final sums liabilities are appropriate, their level and volatility.

- The definition of "local" works and managing instances where local works are complete before the wider network is compliant.

- Whether it is appropriate for existing users to, in effect, retain first refusal over existing capacity and the level of user commitment.

2.8 While the building blocks approach seeks to separate areas, each building block is related and there are interactions between them. Resolving issues in one building block is likely to impact on others. These issues in greater depth within this document. It must be emphasised however, that for ease of discourse in ARODG discussions, "CEC" has generally been referred to as the capacity available following completion only of local works.

2.9 Diagram 2 includes two vertical dotted lines around the word "CEC". This illustrates that it may not be possible to grant CEC until the shared local works, as well as the sole local works, are complete.

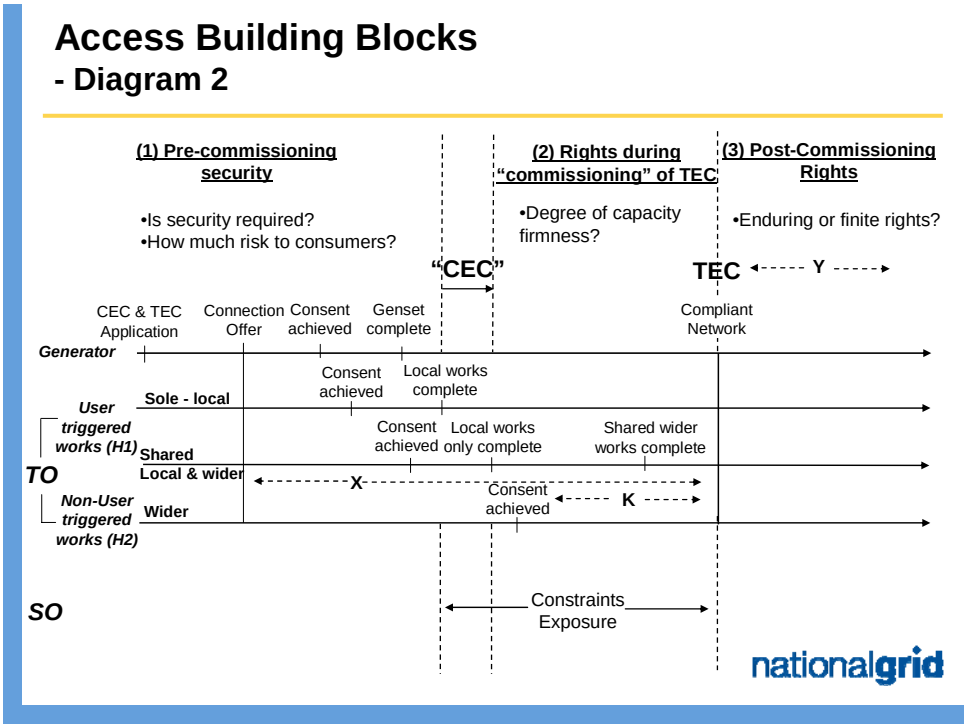
2.10 Diagram 2 also introduces the System Operator (SO) – the party responsible for balancing and operating the network in real time - as a further interested party. The SO would manage any additional constraint costs on behalf of other transmission connected parties if capacity is allocated before the network is compliant with the GB SQSS. To the degree that these constraint costs form part of an SO Incentive Scheme, the SO may bear part of the risk of additional constraint costs.

2.11 The diagram uses the parameters X, K, and Y. These are defined below and are used consistently throughout the document:

- X is the total time it takes from the signing of a connection offer to the completion of investment such that the transmission network is compliant with planning standards. In the current regime, X varies on a project by project basis.

- K is the time taken to deliver a compliant transmission network following granting of all consents. In the current regime, K varies on a project by project basis.

- Y is the period over which all users are required to commit to paying transmission charges. Y=1 year in the current regime.



2.12 This report addresses each of the access building blocks in turn, setting out the existing arrangements, the potential issues associated with these arrangements and the range of options for amending these arrangements. It then combines options from each access building block to create a number of illustrative packages of access arrangements. The ability of these illustrative options to address the issues raised in this document is also considered.

3. Security

3.1 The first area examined by the group in constructing options was the security arrangements required to provide a connection to and rights to use the network.

Existing arrangements

3.2 At present a user wishing to connect to the transmission network will first apply for a connection, paying the application fee necessary to cover the costs of network studies. National Grid (with input from the Scottish transmission licensees) will assess applications on a broadly first-come-first-served basis, resulting in a connection offer being made. This offer will contain a likely date at which connection will be possible.

3.3 The offer will include detail of works which are anticipated to be required to complete the connection, and reinforce the network more generally such that it continues to comply with the planning standards. The offer will also contain an estimated cost profile for works. If the generator accepts the offer, it is required to post security against the level of costs committed by transmission companies. These costs are reassessed on an ongoing basis, as technical design changes, and as the underwriting of costs by other applicants' changes. This security is termed final sums liabilities. At any point in time at least 100% of the costs committed to works are covered by new applicants collectively.

3.4 National Grid has recently modified its approach to FSL to group together projects and ensure that system designs are efficient. This approach aims to optimise designs to accommodate multiple applicants and shares the liability for some costs among these applicants. This approach is termed 'clustering'[2].

3.5 Once all works are completed the generator is no longer liable for FSL and is liable for a years worth of use of system charges on an ongoing basis.

3.6 The existing FSL provisions are a response by National Grid to a statutory obligation to ensure that network developments are economic and efficient. The method of determining final sums is not set out in a modifiable industry code, although National Grid has published guidance notes on its application.

Issues identified with the existing arrangements

3.7 A number of factors, including the Government's introduction of the Renewables Obligation, have created an unprecedented demand for connection to the transmission network. This has resulted in a significant demand for capacity in several areas of the network, particularly

[2] Details of National Grid's clustering methodology are available in 'Principles of Clustering, sharing of final sums and termination'. Available at http://www.nationalgrid.com/NR/rdonlyres/73C05C4A-C15D-45F7-B0EF-3AE1EAADEFAF/6522/principles_of_clust_finalsums_term_v4a.pdf

Northern England and Scotland. A queue for capacity has formed with potentially long lead times before parties are able to connect – connection dates as far out as 2015 have been offered in parts of the country - in part due to the time taken to complete the necessary reinforcements.

3.8 The existing system has the potential to allow a party to apply for connection prior to incurring significant cost. In the first instance, because liabilities only ramp up when work on transmission upgrades begins. This has contributed to a situation in which the queue includes a large number of projects which are unlikely to connect. While the FSL mechanism will filter out those projects over time, it does create an uncertain environment for investment in the short-term and a potentially onerous financial burden for projects in the short to medium term. The current mechanism does not provide the most effective method of focusing transmission network investment where it is most needed.

3.9 A related consequence of this uncertainty is that the amount that must be secured by connecting parties can be large and volatile. In some instances significant liabilities are incurred very soon after signing the offer which can expose the generator to significant levels of risk early in the project. As parties drop out of the queue for access, large liabilities can be transferred to other applicants. Potentially these factors represent a barrier to entry and reduce the effectiveness of competition. In the case of a non-clustered project, a relatively small connection can trigger the need for wider reinforcement, which that project may be unable to secure and, in the case of a clustered project, if a party leaves the cluster and is not replaced, all FSL will be reapportioned across the remaining parties.

3.10 Group members suggested that the governance of security provisions lacks transparency. The inability of a system user to suggest modifications to these arrangements was also noted.

OPTIONS

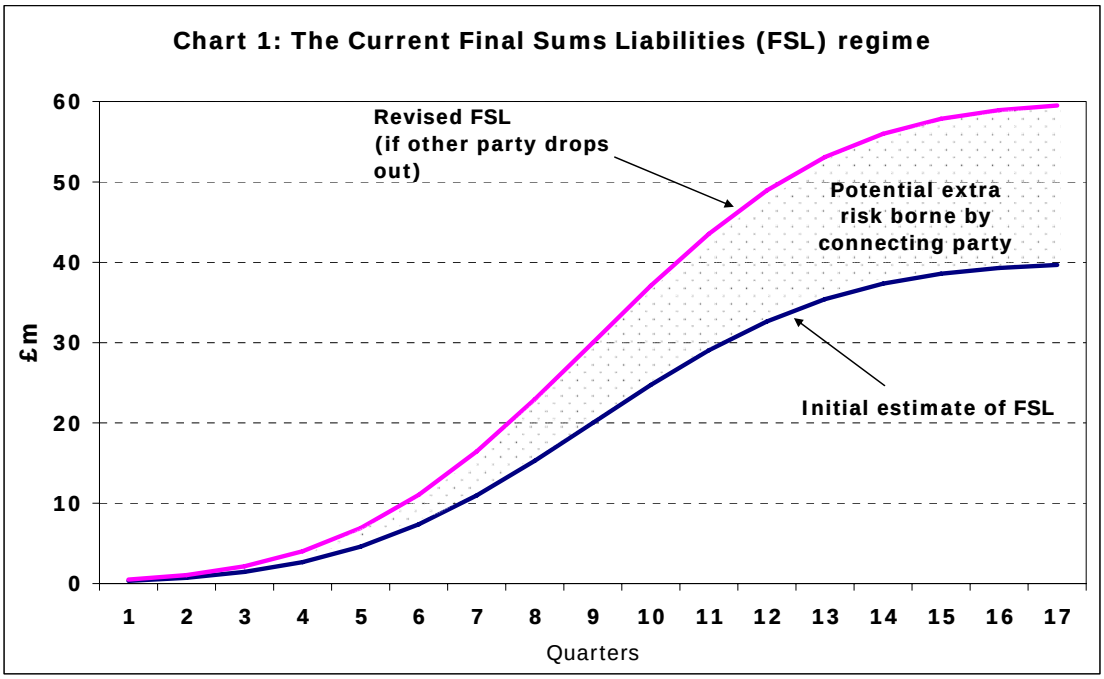
3.11 There is a wide spectrum of options for change, ranging from replacing FSL with a fixed liability (based on some proxy of relevant costs), to minor amendments to FSL in its current form. Any move away from the existing arrangements will represent a transfer of risk between parties. It will be important to consider developments in the other areas detailed in this report in considering the appropriate balance of risk. The Group did not consider increasing the overall security requirements. Options which involve total levels of security lower than actual costs (and potentially the replacement of FSL) were considered. We have sought to characterise options under five headings:

(i) "The Status-Quo"

3.12 One option would make no changes to the existing arrangements. There would be no transfer of risk between parties and the approach would not alter the timing, magnitude or volatility of liabilities.

3.13 The existing position is illustrated below using a hypothetical example. The example is of a new generator with estimated £10m of local connection works, and estimated £30m of deeper works (some of which

represents a share of the cost of works which are common to a number of users) scheduled to be completed over four years.



3.14 Chart 1 above shows how risk is currently allocated, and how the FSL increases over time as costs are incurred. Three points are worth noting. First, FSL is relatively low to start with. Second, any variations between estimated and actual committed costs attributable to the individual connecting party are underwritten 100% by the connecting party. This can include shared costs, of either clustered or wider reinforcements, if these costs are re-apportioned as other parties drop out of the queue – this can shift a party's liability from the lower (blue) curve in the above diagram to a higher profile of liabilities, such as that demonstrated by the pink curve. Third, National Grid (and end consumers) receives 100% protection against the cost of unnecessary investment. The connecting parties bear all risk.

(ii) "Date stamped FSL"

3.15 The option involves making the indicative profile of costs provided as part of a connection offer (the blue curve in Chart 2) firm from the point at which the connection offer is accepted. This would effectively commit a user to the solid line in the diagram below. From this point the security required of a user would increase in a pre-defined way – but the user would not be required to underwrite variations from this initial estimate.

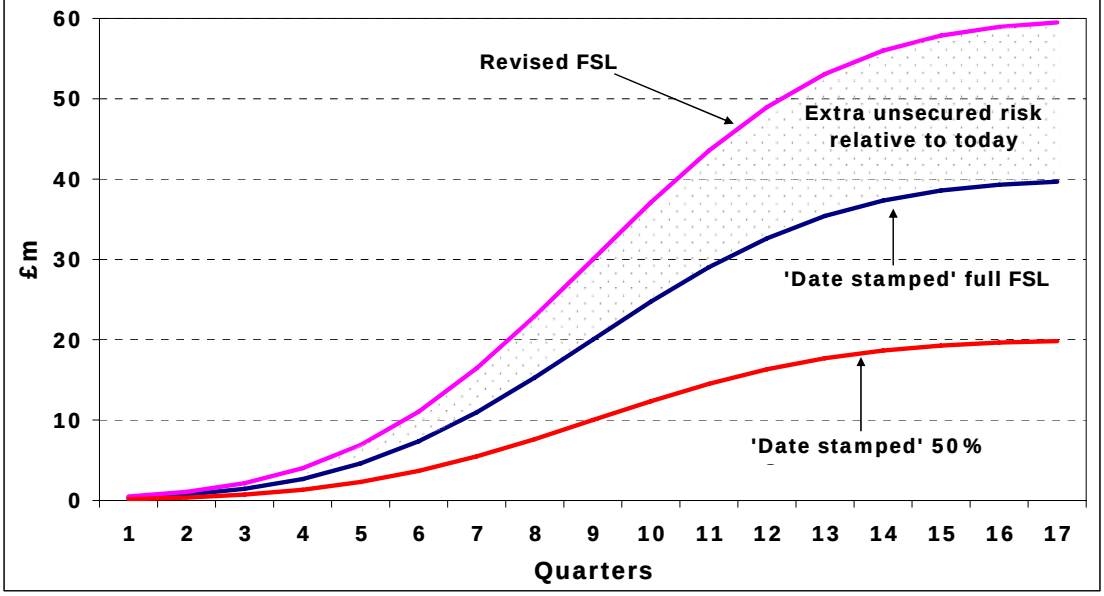
3.16 This option would move the risk that outturn costs were different to a pre-agreed profile of costs from new connectees to, in the first instance, transmission licensees. However, this option, or a variant of it, might be expected to increase certainty to users liable for FSL – fixing the level of liabilities and removing the volatility.

3.17 This approach could result, in practice, in greater than or less than 100% of actual costs being covered by users. However, it has been suggested that this approach would secure less than 100% of committed costs, exposing transmission licensees to a systematically greater level of risk,

where projects are clustered and there may be an expectation that a number of projects will leave the cluster.

3.18 There are a number of variants to this model. One such variant would see FSL being fixed at a level lower than the profile based on underwriting 100% of project costs, e.g. 50% as shown by the red curve. Another variant would be for the 'date stamped FSL' to be a maximum – with reductions in actual costs relative to estimated costs being reflected to the user in lower security requirements. In this case, the FSL profile could be adjusted to recover the agreed proportion of costs or the 'S' curve could be scaled. This option (and the variant) is illustrated in Chart 2, using the same hypothetical example as used in Chart 1.

Chart 2: (a) Full and (b) 50% 'Date stamped' FSL



3.19 A similar variant to this option was first presented by E.ON at the 16th February seminar[3]. This focussed on providing certainty over the profile of security, but additionally suggested that a fixed, lower, £/kW figure should be payable prior to key milestones within a project having been reached. For example, a fixed fee could be payable until the generator achieved consents and, after this point, its profile of liabilities could revert to the date stamped profile.

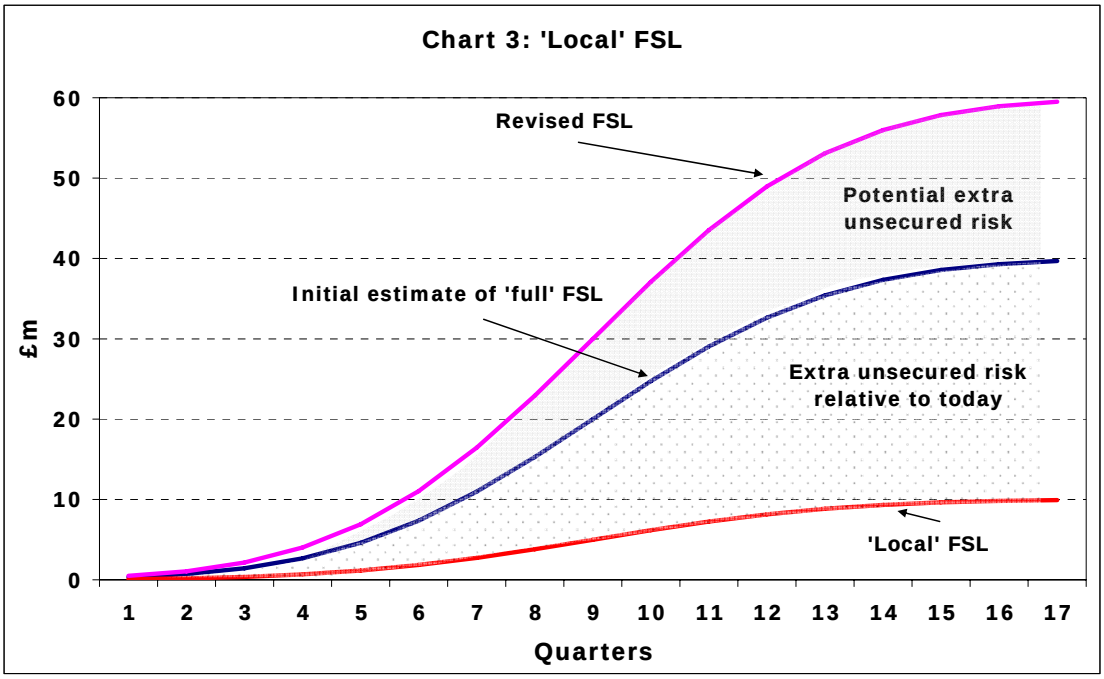
(iii) "Local FSL"

3.20 This option would see FSL being required against assets required to provide the physical connection to the network, but not for 'deeper' works. This option is illustrated by the red line on the diagram below, again using the same hypothetical example. In Chart 3 we do not illustrate the possibility of initial FSL being revised (e.g. as other users drop out of the queue) – but it should be noted that this would increase

[3] Details of the presentations given at this seminar can be found at the following location: http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/14080_Elec_Incentives_16_Feb_Seminar.pdf?wtfrom=/ofgem/work/index.jsp&section=/areasofwork/transpcr.

the risk exposure to, in the first instance, transmission licensees. It can be seen that there is a considerable increase in unsecured risk, equal to the costs of wider works, and an additional potential for risk to increase if costs vary from the initial estimated profile.

3.21 This option would reduce the level, and flatten the profile, of FSL. It is also likely to reduce the volatility of FSL – because local works are likely to be less dependent on the actions of other applicants. However, in the event that outturn costs were greater than the security provided, there would be a transfer of risk from connecting generators to transmission licensees and, to the extent that these costs were reflected in charges, network users and ultimately consumers. The option would provide no security against wider works and it may be necessary to consider other mechanisms, such as those in chapter 5, to provide this.



(iv) "Fixed sum"

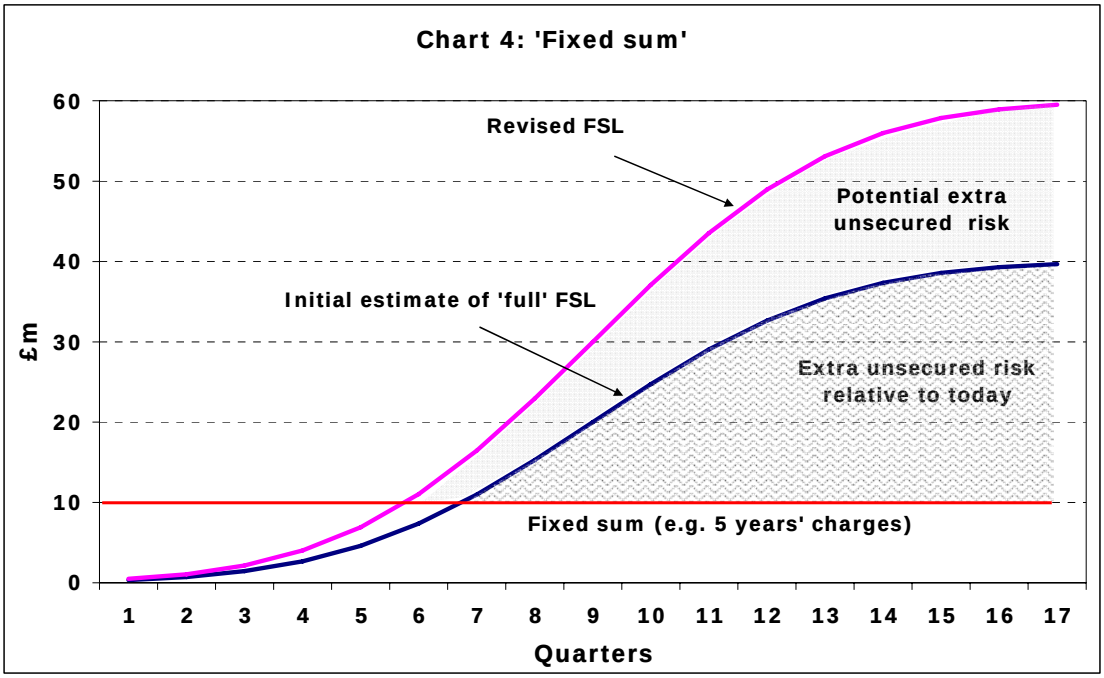
3.22 The Group suggested that some form of fixed sum could replace the existing FSL. This could be posted as an upfront cost, similar to an application fee, or to a pre-agreed profile. A range of methods of calculating the sum exist. One method may be a multiple of annual use of system charges. This would create a locationally varying sum, although other approaches could create a uniform sum. A sum of security calculated using a multiple of use of system charges was put forward because it reflected an expectation of what the user would contribute to costs of access provision in the event that it connected to the network.

3.23 This option would reduce issues associated with the volatility of FSL, potentially aiding development funding. The option of a lower level of FSL prior to key milestones may further reduce risk for the connecting generator. However, if the fixed sum posted by new generators is lower

than the costs incurred by transmission licensees in investing to accommodate them, there will be a transfer of risk to licensees.

3.24 It was argued that this option would leave the wider community of system users neutral to whether a generator connected or not. It was noted that in the event that a party connected to the network, it would pay TNUoS charges and that, under this approach, were it not to connect, the GBSO would still receive that number of years' worth of revenue. However, it was also argued that the TNUoS approach could expose a new entrant to a higher initial exposure than the present FSL arrangements, which could act as an increased barrier to entry. The Group noted that in considering an appropriate sum, it would be important to consider the treatment of negative charging zones.

3.25 The fixed sum option is illustrated in Chart 4 below, again using the same hypothetical example. Clearly, the changes in the allocation of risk between this option and the status quo (and other options) depend on the choice of proxy. This illustrative example uses a proxy which gives an amount of £10m (or 33% of the cost of the deeper reinforcement works initially identified). In this case there is a transfer of risk equal to the area under the outturn cost curve and the red fixed sum line.



3.26 A variant of this model would effectively combine it with option (ii). A generator would be required to post the minimum of the fixed proxy described above or the amount required under the date stamped S curve approach. On the diagram above this would mean a generator's liabilities followed the blue curve initially but were capped at £10m by the red line.

(v) "Local FSL plus fixed sum"

3.27 This option would combine elements of options (ii) and (iii). A generator would be required to provide FSL, potentially 'date stamped', against the cost of providing the local works needed to provide a connection to the network. It would also be required to commit to a fixed sum (for

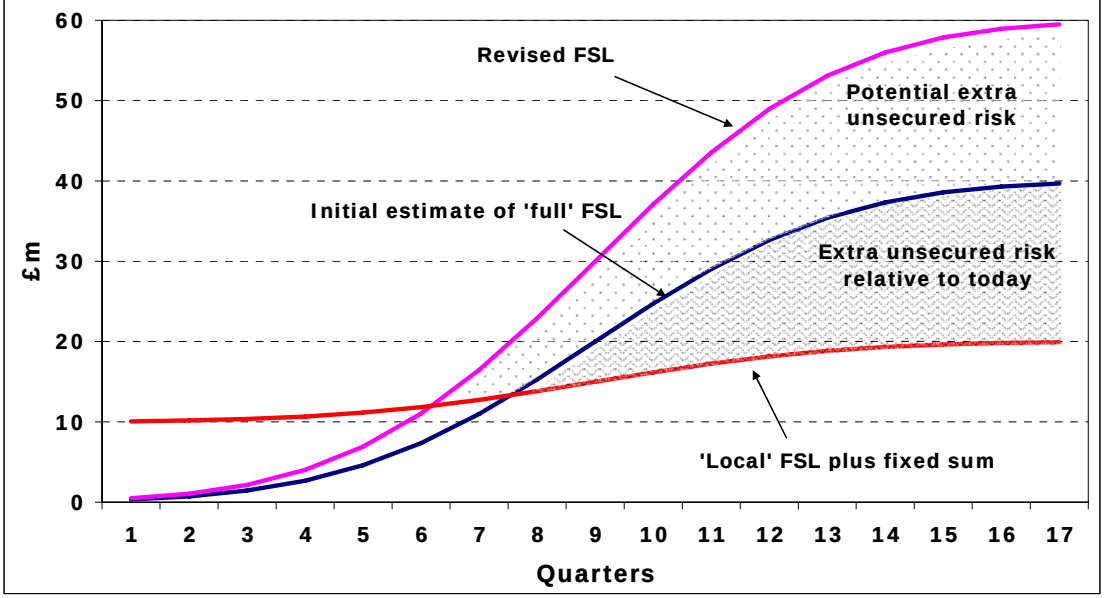
example a multiple of a number of years worth of TNUoS charges) to secure the cost of the deeper reinforcement.

3.28 This option would increase the total cost being underwritten relative to option (ii), would arguably be a closer mapping to actual costs than (iii) – and would reduce the volatility of the liability for the applicant. There would however still be a transfer of risk from each new connectee to system users.

3.29 The option may complement an approach where users applied for CEC and TEC separately. The local FSL could be posted to secure the assets necessary to provide a physical network connection, while the fixed sum would only be required at the point when TEC was requested, which could (though it may not often be the case) be later than the CEC application date.

3.30 This option is illustrated in Chart 5 below, using the same hypothetical example as used previously. Again, it should be noted that the sharing of risk depends on the method of calculating the fixed sum. This illustrative example uses a proxy which gives an amount of £10m (or 33% of the cost of the deeper reinforcement works initially identified).

Chart 5: 'Local FSL plus fixed sum'



Implementation

3.31 The Group considered how an amendment to the existing FSL provisions could be implemented. The difficulties associated with modifying arrangements which are not clearly identified in industry codes were firstly noted and some group members considered that it would be desirable for these provisions to be codified. The counter-argument was made that the current arrangements offer benefits in terms of the time it would take to make alterations to the present methodology. The Group also noted that the level of security required will be dependent on the overall access framework adopted. A number of possible illustrative options are discussed in Chapter 6.

3.32 It was suggested that a change to the CUSC could effect a change to security. However, to the extent that greater costs fell on the SO, it was noted that a change to use of system charges (and possibly allowed revenues) might be needed to apportion this cost across system users, were it deemed appropriate, and a change to the SO-TO code required to allocate increased costs and use of system income between Transmission licensees.

4. Restricted rights

4.1 The second access building block considered by the group relates to the period between a generator being physically able to export to the network (i.e. it has been granted CEC) and the point at which it is able, if it so wishes, to secure an unrestricted access right.

4.2 It is theoretically possible for a user to be in a position to purchase restricted rights for a variety of reasons. The generator may have mothballed its plant, and relinquished its rights to TEC, or it may be economic for the owner of a plant, for example nearing the end of its life, to take a decision to buy a restricted right. Alternatively, a party may have chosen to deviate from the standard practice of applying for CEC and TEC simultaneously and sought a restricted right for the period between the completion of the connection to the network and the completion of wider works to ensure the system complies with the necessary standards.

4.3 The duration of this period depends on the process through which users can secure unrestricted rights (discussed in chapter 5), and choices by the user. It is possible, although the general view of group members was that it would be unlikely, that users would opt for restricted rights on an enduring basis. These rights are generally viewed as 'stop-gaps'.

Existing arrangements

4.4 At present, users are able to secure within-year access through two classes of products, Short Term TEC (STTEC) and Limited Duration TEC (LDTEC). Short Term TEC provides a user with access for a period of 28, 35 or 42 days of access, depending on the type of STTEC purchased, at a premium price relative to 'unrestricted' TEC if used throughout the year.

4.5 Limited Duration TEC is available in two forms, Profiled Block LDTEC, and Indicative Profiled Block LDTEC. The first variant provides an access right that can extend to the end of the Financial Year and is described by a profile that is firm when offered. Indicative Profiled Block LDTEC allows National Grid to indicate the profile of capacity that may be available and to profile access on a firm basis at seven week's notice if the offer is accepted. The actual capacity provided may be higher or lower than the indicative profile offered. The LDTEC products are not charged at a premium price relative to unrestricted TEC when used for the maximum periods within a year. Applications for existing short term products are assessed on a first-come first-served basis. Both STTEC and its variants and LDTEC will only be granted in the event that no constraint is created or exacerbated.

4.6 A recent amendment to the CUSC (CAP068)[4] introduced the possibility of trading firm access rights in advance of the beginning of a year. The

[4] For details of CAP068: 'Competing Requests for TEC' see http://www.nationalgrid.com/NR/rdonlyres/55E614AF-AC14-4AFE-859B-A8EB22C3D477/5171/AuthorityDecisionLetter.pdf

trade is negotiated between parties who then jointly approach National Grid who provides an exchange rate for that particular transaction at that particular point in time.

4.7 Several group members also noted that examples exist where technical solutions, such as intertrips (which often need to be accompanied by derogations against security standards), have allowed increased use of existing capacity.

Issues identified with the existing arrangements

4.8 A number of parties have questioned whether the existing range of products makes most effective use of available capacity. It was also suggested that there might be greater value in restricted products in the context of the current queue.

OPTIONS

4.9 In this chapter we look at the situation where there are recognised physical limits to the volume of unrestricted rights. There are two, possibly complementary, responses. First, seek to squeeze additional capacity out of the prevailing physical network through products other than unrestricted access (TEC), LDTEC or STTEC. Second, by allowing access products (such as TEC, LDTEC or STTEC) already allocated to be reallocated (or traded) between users.

4.10 The options for change can be subdivided into categories where capacity is available during some periods, capacity is unavailable and where technical solutions can make more capacity available.

(i) "More products"

4.11 The Group considered the different generic products that might potentially be developed, and compared them to the suite of products that are available currently. All of these potential products are, by definition, more restricted versions of TEC in its current form. However, it should be noted that analysis conducted by National Grid at the request of the group suggested that the availability of capacity was limited and that this situation may be expected to continue for the foreseeable future in parts of the network. There are, in essence, three possible types of restriction:

- **Duration**: TEC in its current form is open-ended. More restricted products might specify an end date.

- **Volume profile**: TEC in its current form is a right to export electricity up to the specified level at any time. More restricted products might specify a profile of rights which varies over time.

- **Compensation**: TEC, LDTEC and STTEC all have the same form of compensation if the physical rights prove to be unavailable once those rights have been granted. They are 'financially-firm'. The level of compensation is the value perceived by the user at that particular point in time. Alternative products might place restrictions on the compensation payable.

Examples of duration restrictions

4.12 While TEC is currently an open-ended right, LDTEC and STTEC are rights of limited duration. In these cases, the rights cannot endure beyond the end of the charging year. They are 'within-year' rights.

4.13 The group identified a number of theoretical alternatives which adopted different forms of restriction on duration. These included:

- '**Interim products**': This form of product would be available until TEC was made available to the user. Depending on the process adopted for granting TEC this could be a number of years, and could be uncertain.

- **Longer term 'fixed duration' products**: This form of product would be available for a set period of time, but this period of time would not necessarily be constrained to be 'within-year'.

4.14 An issue raised by the group in the context of these products related to the quality of information available to National Grid at the point at which it might consider releasing such products. The current 'within-year' products are made available using an assessment of what is consistent with 'operating standards'. In turn, this requires short-term operational information from network users. The certainty of operational information in timescales beyond the current year was raised as a potential concern.

4.15 In this context, it was noted that the current 'within-year' products are, by definition, only released by National Grid when it is confident that making the rights available will not increase constraints on the network. Poorer quality information in timescales beyond 'within-year' might make this test a difficult one to meet.

Examples of volume profile restrictions

4.16 TEC in its current form provides the holder with the right to generate electricity up to the level of TEC at any time during the year. The group identified theoretical alternatives which placed restrictions on the profile of rights. LDTEC is one such example of a pre-defined volume profile (which currently can be provided as an indicative profile or a firm profile).

4.17 There are other possible variants. One example, discussed in the group would be a 'maximum total' access right – where the user would be limited to generate up to a maximum cumulative amount over a specified period, and once this limit was reached would not have any further access rights. Another example, which might potentially be used in tandem with a total volume restriction, would be for the access right to be set to zero on specified days (or parts of the day). An example would be a product which afforded no right to generate over the winter months.

Examples of compensation restrictions

4.18 TEC, STTEC and LDTEC are all 'financially-firm' products. This means that once they have been granted, the user is entitled to be compensated on the basis of the user's perceived value in the event that the right cannot be accommodated physically (except in certain circumstances specified in the CUSC, where administered compensation arrangements apply).

4.19 There is, in theory, more scope to use restrictions on compensation as a means of defining new access products. These options would specify compensation, and the circumstances in which it would be paid, in advance. One such example is an 'interruptible' or 'non-firm' product, under which compensation would be zero in some circumstances.

4.20 The group discussed the commercial potential for such products, with the general conclusion being that some degree of certainty over the likely extent of uncompensated 'interruption' would be needed to make the product commercially viable.

4.21 It should be noted that while this 'volume profile' and 'compensation restrictions' might look similar, there are important differences. To illustrate, a user who receives no compensation if it is constrained off during winter will still generate if network conditions permit, whereas a user who has a profiled right excluding the winter months will never generate during winter.

Hybrid options

4.22 There are a large number of different ways in which the types of restrictions described above might be combined. A product which is interruptible after a specified maximum volume has been reached is one such example – but there are many others.

4.23 These options represent possible ways of extending the range of products, while retaining control of the potential costs of not being able to accommodate rights physically on the network. A key impact to be considered in any option will be the impact on the volume and cost of constraints. This raises wider interactions with how such costs are treated in the context of National Grid's revenue restriction, and to the extent there is a revenue allowance to cover all or some of these costs, how the effects are passed on through charges. The impact on the setting of imbalance prices under the Balancing and Settlement Code (BSC) may also require consideration.

How these products might be allocated

4.24 In developing any alternative products it will also be necessary to consider how they are sold, including in circumstances where more than one party might wish to buy a particular product in a particular location at a particular point in time. In addition the hierarchy amongst restricted products and their interaction with unrestricted access products will need to be considered. Two options under this approach are, allocating products on a first-come-first-served basis, or on the basis of the user's willingness to pay.

4.25 In the event that there are a greater number of applications for a restricted access product than capacity available, a first-come-first-served system may have the potential to create a queue and create new barriers to market entry.

4.26 An alternative mechanism would see rationing on the basis of the value placed on the capacity by a user. Such an approach would require the development of systems for notifying National Grid of the value placed on amounts of capacity and a method of notifying parties of where and when capacity was available.

Implementation

4.27 The development of new products is primarily a matter for the CUSC. The introduction of TEC, STTEC and LDTEC were driven through the CUSC modification process, and it would appear that this is the most appropriate route for any other new products. CUSC modifications can be raised by any CUSC party.

4.28 There are a number of possible consequential changes that would flow from, and would need to be progressed in parallel with, the development of new products in the CUSC.

- Any new access product would need to be accommodated in National Grid's charging methodology. National Grid has responsibility for developing proposed changes to its methodology.

- The ability for National Grid to identify how much of a particular product can be released might depend on information provided to it by industry parties. The obligations to provide information are set out in the CUSC and the Grid Code and changes to both may be required.

- If new products are introduced then it could impact on National Grid's revenue restriction. This will determine whether there is any net addition to the revenues of National Grid if additional rights are released. The scope for additional income will change National Grid's incentives to release products, and will impact on charges to (some) users. These need to be considered together with any additional compensation mechanisms.

- The impact of any change in approach on the way in which imbalance prices are set under the BSC may require consideration.

4.29 The detail of how the revenue restriction is structured is a matter for Ofgem. Ofgem has undertaken to provide an early indication of how new products might be reflected in the revenue restriction as the detail of such products unfolds. Ofgem noted in the group the current model in gas entry, under which income for National Grid from the release of 'discretionary' access products is counted against the costs of balancing the network (and National Grid can retain a share of any 'profits' relative to forecast system operation costs) as one possible way of addressing this issue.

(ii) "Reallocating capacity"

4.30 It was noted that in the event that no capacity, or insufficient capacity, could be released (through whatever suite of access products might be available), the only way for a user who had not previously bought rights to secure access would involve reallocating access rights between users, subject to a user who holds rights being willing to sell capacity and National Grid calculating an exchange rate.

4.31 There are three broad forms of trading:

- **Ad hoc facilitated transactions**: Parties would approach each other to discuss potential trades – and if it looked mutually beneficial would approach National Grid, who would provide a bespoke 'exchange rate'. For example, National Grid would translate a number of months worth of the seller's TEC into an LDTEC product which the buyer could then buy. This 'exchange rate' would be specific to the individual transaction.

- **Facilitated trading**: National Grid would publish 'exchange rate' information on a frequently updated basis, and would broker trades if the published exchange rates were mutually satisfactory. Users would assess their willingness to sell, or to buy, at the published rates – and trade would be brokered by National Grid.

- **Centralised trading**: An agency, potentially other than National Grid, would keep track of all holdings of capacity, and there would be a process of settlements to capture the effects of any trading. This system would require the publication of exchange rate information (probably by National Grid) and the provision of information to National Grid to enable it to track capacity holdings to enable it to operate the system in real time. There may also need to be a system to resolve capacity imbalances.

4.32 One limited variant of the centralised trading option, highlighted by the group, is the concept of 'portfolio TEC'. Under this option, access rights are allocated to an area of the network, and parties within that area are able to exchange rights between themselves. This is broadly equivalent to facilitated trading with exchange rates being set equal to one between certain specified points on the network.

4.33 Some group members noted that there was some scope for facilitated trading of access rights in the prevailing arrangements – although this was clearly limited by the range of products. In the context of TEC, this means giving up the right to TEC indefinitely. Some group members saw potential scope in being able to trade TEC for short periods of time, which did not seem compatible with the current arrangements.

Implementation

4.34 A number of group members noted that the issue of developing structures to facilitate the trading of access rights had been discussed in detail under a previous CUSC standing group, the Transmission Access

Standing Group. This process had highlighted the significant implementation issues associated with some models of decentralised trading. The key implementation issue appeared to be how the ownership of access rights was tracked in real time. Solving this issue appeared to involve significant systems costs, and major changes to the underlying provisions of the CUSC and related industry codes.

5. Unrestricted access

5.1 The third access building block considered by the group relates to the period in which users, both existing and new, are able to secure the least restricted form of access rights. Under the current arrangements, this is TEC.

Existing arrangements

5.2 TEC is an open-ended right to export electricity on to the transmission system up to the specified level at any point in time. A network user with TEC has an obligation to pay use of system charges on that level of TEC, and has the right to reduce his TEC at any point in time. The liability for use of system charges on any reduced level of TEC applies from the following April.

5.3 All applications for TEC, either from new generators or from existing generators who want to increase their level of TEC, are treated in the same way[5]. Applications are assessed against the prevailing contractual background, including TEC already allocated and offers of new TEC already processed, and a set of works on the network are identified. Broadly speaking, the works are those required to accommodate the new TEC plus all existing TEC, while continuing to comply with specified standards for network (the GB Security and Quality of Supply Standards, 'GB SQSS').

5.4 As discussed in chapter 3, the user is required to provide financial security against the cost of some of these works. When the date agreed with National Grid is reached[6], the requirement for financial security falls away.

5.5 A user is provided with TEC once all the works listed in the offer of connection have been completed and are in service. The date of delivery of TEC can therefore be uncertain, and can be affected by factors which influence the completion time of the relevant network investment, such as the time taken for transmission companies to obtain consents and wayleaves.

Issues identified with the existing arrangements

5.6 Ofgem has focused on two particular aspects of the current arrangements as raising potential issues in the light of its statutory duty to protect the interests of consumers and in the light of comments from industry parties and other stakeholders. These have been discussed in the working group:

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[5] This is the case on an ongoing basis. The Group noted that the BETTA transitional arrangements meant applications received prior to 1 September 2004 were assessed against a different background.
[6] This date is normally written into the construction agreement and is based on completion of transmission and the user's own works. It may change because of delays in factors such as delays in achieving consents.

- First, the reservation of capacity for existing parties inherent in TEC in its current form – and what this means for the timing of new connections (and therefore competition) and for the information available to the transmission companies to plan efficient investment in the networks; and

- Second, the incentives on transmission companies to get new generators connected to the network in a timely manner.

5.7 The current arrangements, in effect, provide a free reservation of capacity each year for parties at the level of their existing TEC, while requiring new parties (and those existing parties which require additional TEC) to wait for the completion of works until they are provided with capacity. This affords a degree of protection for existing generators against new competition. It could also potentially result in inefficient investment, if an existing generator closes – and exercises its right to hand back TEC – at short notice. While there are requirements on generators to provide operational information to transmission companies, this is not currently backed by significant financial commitments. However, an existing generator bears none of the risk of investment proving to be unnecessary if it decides to close (or mothball) at short notice.

5.8 The current arrangements afford the transmission companies and consumers with a degree of protection against the risk of network investment being delayed – whilst apportioning this risk entirely on to the new connecting generator, cluster of generation or party requiring additional capacity. Any delay to investment timescales results, more or less, in an equivalent delay to the date at which TEC is available. The financial sanctions for transmission companies for being late are relatively limited.

5.9 While transmission companies cannot control all of the risks of project delivery (the most obvious example where the transmission companies have only limited control of the risk of consents for network investment being delayed or not be granted), there are delivery risks that the transmission companies are best placed to manage. It could be argued that the current arrangements do not create strong incentives to manage these risks efficiently. Again, this is potentially significant in the context of strong demand for market entry.

5.10 The Group discussed the value of information on disconnections in detail, without a consensus being reached. National Grid suggested that there may be benefits to system planning with longer-term capacity bookings by existing generators, while generators and the Scottish transmission licensees questioned whether this was the case (and noted the potential additional cost to consumers of any increased liabilities). The Group also considered whether there were alternative methods of providing relevant information to National Grid, e.g. through enhanced obligations in the Grid Code[7].

5.11 Some group members questioned whether investment was being delivered as quickly as practicable and noted that the lack of certainty over when an unrestricted right will be provided increases risk to

[7] For example by increasing the provisions contained within Operating Code 2 (OC2).

connecting parties. These group members therefore questioned whether the current system promotes competition as effectively as it might.

OPTIONS

5.12 The dimension of the options in this section can be separated into (a) rights, and (b) obligations. The current arrangements can be described in this framework as:

- **Rights**: a network user can apply for an open-ended right to use the network at any time up to a specified level of export. It also has the option to reduce its specified level of export unilaterally before the start of each charging year. The user is granted this right once specified physical works are completed.

- **Obligations**: a network user is obliged to provide financial security against the cost of a subset of the specified works (which can be updated) prior to the access rights being granted, and is obliged to pay use of system charges for the specified level of export once the access rights have been granted.

5.13 The options discussed in this section are, in essence, different combinations of rights and obligations.

Rights

5.14 The current arrangements provide existing generators with an open-ended right to use the network, and provide new users with the same right at an undefined point in the future when all necessary network investment is complete.

5.15 All of the options below involve the concept of an 'unconstrained release' of capacity at some point in the future. This means that no user who is willing to make the necessary financial commitment will be denied access to the network indefinitely. The options, in essence, boil down to what conditions need to be met before the 'unconstrained release' of capacity occurs, for both new and existing generators.

5.16 There is very limited scope for options which provide new generators with their access rights any later than is currently the case. There are, however, a range of options which provide new generators with TEC (or its equivalent) at an earlier (or at least more certain) point in time.

5.17 The options set out below illustrate this range of options. X (the time from signing an offer) and K (the time from the granting of all transmission consents). These options are demonstrated graphically in the access building blocks diagram in chapter 2.

(i) "Consents plus K"

5.18 This approach would seek to provide a firm delivery date, assuming that the transmission companies cannot significantly influence when consents for network extension and reinforcement works are granted. It would provide a new user with TEC (or its equivalent) K years after the

transmission companies had obtained all the necessary consents for the works required.

5.19 In deriving the appropriate value for K, it will be necessary to consider construction timescales and system access issues. However, consents are typically time limited – Section 37 consents are valid for 5 years - and this will need to be acknowledged. The greater the value of K, the greater will be the level of consumer protection and the lower the value of K the greater the level of risk to transmission licensees and other system users. Therefore, these factors will need to be traded off in determining an appropriate value for K. It may be appropriate to consider whether the level of K should be a single number, or dependent on, for example, the size of the project. Equally, the extent to which a user is able to negotiate around the value of K may merit consideration.

5.20 An option such as this would involve a new potential cost for the transmission companies, i.e. the cost of buying-back capacity that is delivered later than K years after consents are granted. The risk exposure of the transmission companies under this regime would depend on the treatment of these potential additional costs in their respective revenue restrictions. If all or some of the additional costs 'stuck' with the transmission companies, then this would create a financial incentive to deliver capacity on time and may provide rewards for early delivery.

5.21 If any of the additional costs of buying-back capacity were allowed to be passed through in National Grid's charges, then there would be a risk of increased costs to system users and, ultimately, consumers. This would also require consideration of how such costs should be charged out to users of the network.

(ii) "Delivery in no more than X years"

5.22 This option would be similar to the 'consent plus K' option above, but would remove the trigger of consents being obtained. Capacity would be provided a fixed time after a given point. This point could, for example, be the date an offer is signed or the completion of a physical connection to the network. This option would seek to provide new users with more certainty as to when their rights will be delivered, but will also involve the transmission companies assuming more risk (in the first instance) of rights being released before network reinforcements are capable of being completed.

5.23 Transmission licensees have limited control over the achievement of consents. Therefore, there may be potentially large costs associated with the option if the transmission companies are consistently unable to deliver capacity within X years. In this case, it will be necessary to consider how these increased costs should be dealt with.

5.24 The most conservative variant of this option would be to set X equal to an estimate of the time needed for an efficient operator to obtain consents and complete the necessary works, assuming there were a robust way to determine this value – and to provide carve outs if there were exceptional difficulties.

(iii) "Delivery once connected locally"

5.25 This option would separate all works for a particular new user into (a) local works required to enable the generator to export on to the main interconnected transmission system, and (b) deeper reinforcement works required to ensure compliance with SQSS. TEC (or its equivalent) would be granted once local works are completed, and would not be contingent on completion of the deeper reinforcement works. The presumption under this option is that local works are completed more quickly than deeper reinforcement works.

5.26 If there were a lag between the completion of local works and the completion of 'deep' reinforcement, then National Grid would be required to manage the consequences of accommodating a level of generation greater than the system could ordinarily cater for, in the same way that it manages constraints currently. This is likely to result in increased costs of balancing the network. For example, if 1000 MW of new generation were connected locally in Scotland one year ahead of commensurate additional capacity being built on the circuits between Beauly and Denny, then congestion management costs would be likely to be significantly higher for a year as a consequence. Scottish transmission licensees suggested that there may be expected to be an enduring bottleneck over the former England – Scotland interconnector circuits.

5.27 A number of group members expressed concern about potential increases in constraint costs under this option, which under current charging arrangements would be smeared across all users. However, other group members stressed that there were a number of ways in which National Grid could manage this situation efficiently – and the costs might not be as high as some parties might anticipate. It was also suggested that arrangements could be developed in which the additional income generated by granting rights earlier than would prevail under the current arrangements might be used to offset any increases in constraint costs.

5.28 There are many variants of this option – some of which involve combining the option with elements of the 'restricted rights' products discussed in chapter 4. For example, National Grid might be obliged to deliver access rights to as soon as local works are completed (or for that matter in, say, three years as per option (ii) above), but this right would have a restriction on compensation attached to it for a period of time, e.g. until two years after all consents have been granted. This type of hybrid option would be a means of adjusting the balance between providing certainty and timely deliver to new users while protecting the generality of users (and consumers) from the risk of spiralling constraint costs.

Implementation

5.29 The Group considered how one of the options above might be implemented.

5.30 In the event that licensees are required to deliver financially-firm capacity by a given date, careful consideration will need to be given to determining what this date is. It will also be appropriate to consider how any new potential cost and revenue streams, for example compensation

for the late delivery of capacity, are accommodated. This may include consideration of whether a system of penalties and rewards needs to be developed to complement the option. Ofgem will be considering these issues in the light of any proposals as part of the ongoing TPCR process.

Obligations

5.31 The key obligation is the length of time a network user (or particular class of network user) is committed to pay for the access rights they wish to buy (or to prove they are available and able to generate in negative charging zones).

5.32 For ease of exposition, we have adopted a generic framework which allows us to consider existing users and new users as separate classes of user. This does not mean that the two groups should necessarily be treated differently. In these examples the parameter A has been used to denote the requirement to post user commitment by new users and the parameter B has been used to denote the commitment for existing users.

5.33 There is a design issue common to all of the options discussed below as to what, exactly, is the user is committing to. The options are (i) to pay the prevailing level of use of system charges for the relevant number of years, (ii) to pay a level of use of system charges fixed for the relevant number of years, or (iii) to pay a 'date stamped' profile of expected use of system charges over the relevant number of years. The least change option is, probably, (i) with security being required against a rolling estimate of what prevailing charges are likely to be over the relevant period.

(i) "Status Quo"

5.34 The status quo can be characterised as A=B=1, all users who have acquired TEC are required to pay charges for a single year.

(ii) "New users commit initially"

5.35 A > 1 and falling over time until A=B=1. Under this option new users would post a commitment on application for TEC, for example to pay charges for a minimum number of years (although other methods of determining this commitment exist), while existing users would continue to be required to pay a single year's worth of TNUoS. Under this option the commitment required of the new user would reduce over time until it was the same as for existing users.

5.36 This option would front-load some of the financial commitment required of new applicants relative to the FSL arrangements of today (It will be appropriate to keep this in mind when considering the security requirements discussed in Chapter 3). As such it could filter projects currently in the queue, increasing the likelihood that those which apply for connection are viable and likely to have achieved all the necessary milestones. This in turn could reduce the uncertainty over where investment was most needed – hence potentially reducing the risk of unnecessary investment. It would, however, continue to treat new and existing network users differently.

(iii) "All users commit"

5.37 A > 1, B > 1. This approach would see all users being obliged to pay for TEC for a number of years. Variants include A being set equal to B and different values being used.

5.38 There are variants of this option. One, which would be broadly equivalent to increasing, to a fixed number of years, the notice period to reduce TEC, would see all users making a rolling ongoing commitment. An alternative variant would see users able to purchase rights for any period above a minimum commitment.

5.39 The variant of A = B would treat all users in the same way, once TEC has been granted. New users would still need to go through the process of applying for TEC and providing financial security prior to TEC being granted (discussed in chapter 3) but there would be no enduring difference in treatment once access was granted.

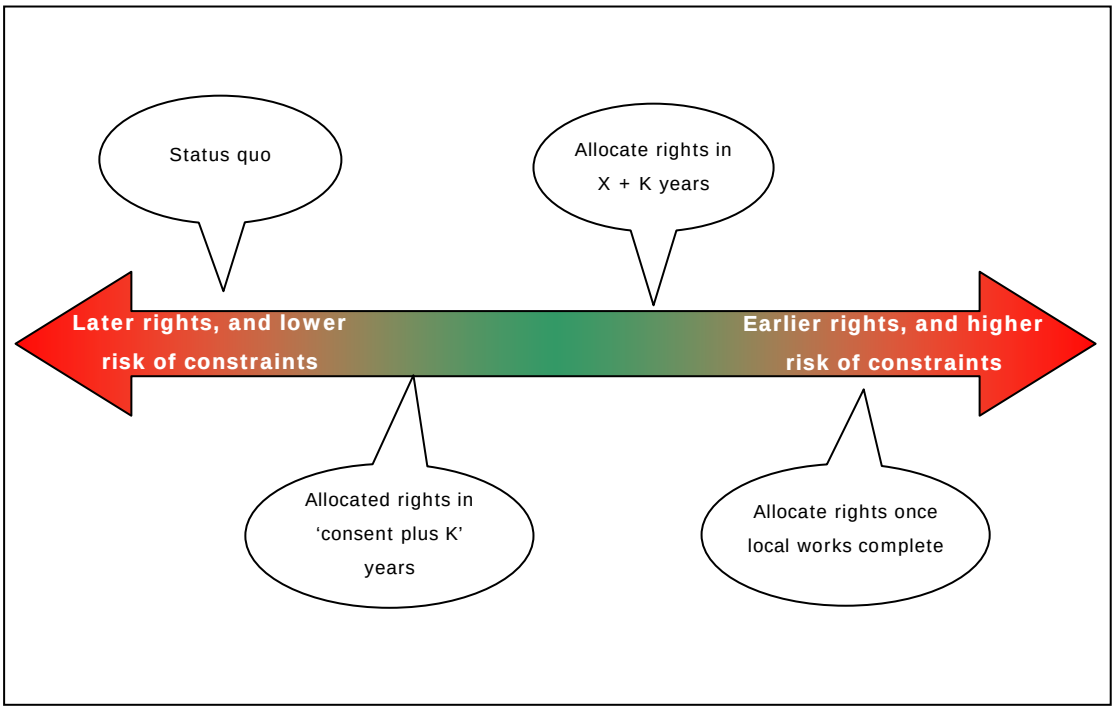
5.40 A variant of this option is to link the commitment to pay directly to the duration of the access right – a so-called 'finite rights' model. If a party commits to pay for access rights for K years, then it could be considered to have bought K annual strips of capacity. A further variant of this model is for K to be a minimum, and to give users the right to buy more than K years if they wish. The defining characteristic of this type of model is that if a user does not make the relevant commitment, then he does not have an access right – and it can be reallocated to another party who is willing to make the commitment.

5.41 This option would provide the transmission companies with a more certain profile of demand for entry capacity. It would also transfer a proportion of the risk of investment proving to be unnecessary because parties choose to close (or reduce their use of the network) on to the party choosing to close (or reduce their operations) earlier than anticipated.

5.42 This option will increase costs of using the network for existing generators relative to today. The additional cost will be the cost of security against the future commitment to pay use of system charges. It was noted that this could increase costs to consumers – and this would be relevant in considering the overall net costs or benefits. Some members of the group also raised concerns that this might result in efficient closure decisions being deferred, because use of system costs would be sunk until the end of the commitment period.

Summary

5.43 The options described in this chapter demonstrate that there is a spectrum of options, trading off the risk of increased costs of delivering rights with earlier delivery of those rights. At one end of the spectrum are the existing arrangements, with the vast majority of risk lying with new connectees and limited obligations being placed on licensees to deliver capacity. At the other extreme is a situation where risk is shifted to licensees who must manage the increased costs associated with providing capacity on a constrained system which does not comply with the required planning standards. This spectrum is illustrated below:



Implementation issues

5.44 Under any option where new and existing users are required to make the same commitment, it will be important to consider how the transition from the existing arrangements may work. It may be deemed appropriate to allow all users to apply for capacity concurrently or, alternatively, to provide a one-off opportunity for existing users, and indeed potentially parties which have received connection offers, to apply for capacity sequentially.

5.45 An important consideration will be the treatment of offers which have already been made to applicants. Some Group members expressed concern that existing offers may be withdrawn or altered, while others suggested that offers already contained provisions for them to be altered via agreements to vary. Further consideration would also need to be given to the necessary amendments to licenses, consequent changes to the price control regime and interactions and money flows between transmission licensees.

6. Illustrative options

6.1 This document has so far considered issues and "building blocks" in relative isolation. However, in considering the extent to which alternative transmission access models are able to address the range of issues which may be perceived as deficiencies within the existing arrangements, it will be important to consider options from each of the three areas as a package.

6.2 At the start of the ARODG process, Ofgem identified two broad areas into which potential problems with the current arrangements could be categorised: Facilitating competition and promoting efficient investment.

6.3 There are several points which may warrant addressing under each of these broad headings. Facilitating competition will involve reducing barriers to market entry, particularly those associated with final sums liabilities, providing increased certainty over when network capacity will be delivered and providing a greater range of options to secure capacity to both new and existing parties. Crucially, it will also ensure that incentives to speculatively apply for capacity are reduced and efficient projects are able to apply for and secure capacity within shorter timescales (and with greater commercial certainty) than today.

6.4 In addressing issues associated with efficient investment, it may be appropriate to focus on the level of commitment provided by new and existing users to transmission companies such that they are able to plan the system more efficiently - minimising the risk that assets are stranded.

6.5 Ofgem have attempted to develop a format which identifies the ability of options to address the issues raised in this document, under the headings identified above. This is presented in the table below. A number of detailed points have been developed under five headings: facilitating market entry, increasing flexibility, facilitating efficient investment, protecting consumers from the risk of asset stranding and addressing the queue for capacity. Each option is assessed against these and awarded a ranking between a × and ✓✓✓ based on its ability to address the issue. For example, in the context of facilitating market entry, the ability to remove all volatility in FSL would earn a ✓✓✓ rating, while an option which provided no incremental benefit when compared to the current arrangements would earn an ×.

6.6 There are numerous permutations and combinations of options. For purely illustrative purposes, this chapter uses the table to identify and outline four illustrative models. It briefly explains each of these and considers how they would change the existing access arrangements and the impact that they may have on a range of industry parties. For the avoidance of doubt, these options, and the ratings awarded in the table, are purely illustrative and should not be considered as the only options worthy of consideration. Nor do they represent preferred options of either Ofgem or individual members of ARODG.

Illustrative option 1

6.7 The first illustrative option involves relatively few changes to the current arrangements. It involves:

- **'Date-stamped 100% FSL**' – the user is required to post security in line with the initial estimate of the profile of local and deep costs as per the current FSL regime. The profile is not then revisited.

- **'Consents plus 2' for new users and no change for existing holders of TEC**. The new user would be allocated TEC 2 years after the transmission companies had gained the consents for all the works (local and 'deep') cited in the connection offer.

- **'Refined status quo' for restricted rights** – parties would have the right to apply for the existing range of products other than TEC in advance of being allocated TEC, and further products might be introduced (only if they were consistent with no expected increases in constraint volumes).

- **Ad hoc facilitated transactions** – the current arrangements would continue where it is open to parties to approach National Grid to explore the basis on which access rights might be exchanged on a case-by-case basis.

6.8 This package of changes would have a relatively minimal impact on existing users, and only a limited impact on new users. It would continue to require new users to provide security against an increasing profile reflecting 100% of the initial estimate of costs of reinforcing the network locally and more widely – although the profile would be fixed in advance.

6.9 Because of the date-stamped FSL, there would be an additional risk for the transmission licensees that the security provided would not be sufficient to cover the works undertaken. This, in turn, could be passed on to consumers. The risk would be that assets would be underutilised for a period of time. The worst case would be that assets were never utilised, i.e. stranded.

6.10 This option would not appear to improve the quality of the information on future patterns of demand for network capacity significantly, either from new users or from existing users, relative to today. The queue would continue in, more or less, its current form – and the quality projects would only be revealed over time as the FSL started to bite.

6.11 The option would, however, address the volatility issue with the current FSL arrangements – which could remove or reduce a perceived barrier to market entry, and in turn better facilitate competition. Having said that, there would only be a minor improvement in the date by which (and certainty with which) new users would be granted TEC.

6.12 The implementation issues with this option are relatively minor. The FSL 'methodology' can be changed unilaterally by National Grid without the

need for a CUSC modification. It should, however, be noted that some group members considered that the method of calculating FSL should, in any event, be set out in CUSC. This would require a CUSC modification. There would be no wider interactions with charging, and the interactions with the price control would also be expected to be relatively minor.

Illustrative option 2

6.13 The second illustrative option retains the focus on new users but spreads financial commitments in a more stable way over a longer period of time, and in return provides new users with greater certainty on when TEC will be provided. It involves:

- **'Local FSL**' – the user is required to post security in line with the (periodically updated) profile of estimated costs of the local works only.
- **'TEC in 3 years and a five year charging commitment'**. The new user would be allocated TEC not more than three years after he signed a contract committing him to pay for TEC (at the prevailing level of charges, and subject to the completion of local works) for a period not less the five years.
- **'Refined Status quo' for restricted rights** – parties would have the right to apply for the existing range of products other than TEC in advance of being allocated TEC, and further products might be introduced (only if they were consistent with no expected increases in constraint volumes)
- **Ad hoc facilitated trading** - the current arrangements would continue where it is open to parties to approach National Grid to explore the basis on which access rights might be exchanged on a case-by-case basis.

6.14 This option would involve more extensive change, but again they would be focused primarily on the treatment of new users. In essence, new users would face a different profile of financial commitment spread over a longer period of time (and would involve less commitment than under the current arrangements in aggregate) – and in return would have greater certainty on when TEC will be provided.

6.15 This option would also potentially shift the risk of delays to the completion of network reinforcements from new users (who currently are not granted rights until the works are complete) to National Grid and potentially the other transmission licensees. In turn, Ofgem would need to assess how, if at all, National Grid (and the other licensees) should be additionally remunerated for managing this risk. If there is an additional revenue allowance associated with managing this risk, then there may also be an interaction with charging – because National Grid will need to establish a means of recovering these allowances through charges.

6.16 The option might be expected to improve (relative to today) the quality of information on the demand for future capacity at the investment stage. When a new user applies for TEC they will make a material financial commitment, and this should act as a filter for projects currently in the queue. The option will also provide greater certainty for new parties on when they will receive their TEC and what their liabilities will

be before and after that date. This might address some of the issues raised in the context of competition.

6.17 The option does, however, continue to treat new users differently to existing users in first four years after TEC is granted. Consequently, it does not address the issue of information on the likely future demand for capacity from existing generators.

6.18 The option would have the implementation issues associated with illustrative option 1, plus additional changes. The delivery of TEC by a fixed date would require changes to CUSC and to associated bilateral agreements. One particular implementation issue is how such revised agreements relate to the offers of connection already signed. One model, which received some support within the group, is that the offer based on the revised arrangements would replace any current offer. The development of any additional restricted rights products would require changes to the CUSC and to the charging methodologies.

6.19 It was noted by some group members that, in any event, the information provided by existing users on future operating plans under the Grid Code should be re-examined in the context of the issues raised by the debate on access arrangements. This might prompt changes to the Grid Code.

Illustrative option 3

6.20 The third illustrative option is an extension of illustrative option 2 above, increasing the range of restricted rights products available to new (and existing) users as an alternative to TEC. It involves:

- **'Local FSL**' – the user is required to post security in line with the (periodically updated) profile of estimated costs of the local works only.

- **'TEC in 3 years and a five year charging commitment'**. The new user would be allocated TEC not more than three years after he signed a contract committing him to pay for TEC (at the prevailing level of charges, and subject to the completion of local works) for an initial period not less the five years.

- **'Less-firm rights'** – a new product (or products) would be made available by National Grid (in a non-discriminatory manner) in advance of TEC being available, which provided users with a minimum volume of generation capacity over a specified period and had associated restrictions on the amount of compensation that would be paid in some circumstances.

- **Facilitated trading** – by publishing indicative exchange rates and details of those seeking to buy and sell capacity, an agent would facilitate trading.

6.21 This option would involve more extensive change, but again they would be focused primarily on the treatment of new users. New users would face a different profile of financial commitment spread over a longer period of time and in return would have greater certainty on when TEC will be provided.

6.22 It would also shift the risk of delays to network reinforcements, including those occurring from consents not being achieved, to transmission licensees. There may again be a need for Ofgem to assess how, if at all, National Grid (and the other licensees) should be additionally remunerated for managing this risk and a possible interaction with charging arrangements. In the period until works could be completed, a system of facilitated trading may allow parties which value access more highly to demonstrate this and procure an existing parties access right.

6.23 The option might be expected to improve (relative to today) the quality of information on the demand for future capacity at the investment stage. It may also be expected to act as a filter for the queue. The option would also provide greater certainty for new parties on when they will receive their TEC and what their liabilities will be before and after that date. This might address some of the issues raised in the context of competition.

6.24 The option does, however, continue to treat new users differently to existing users in first four years after TEC is granted. Consequently, it does not address the issue of information on the likely future demand for capacity from existing generators, although it has been suggested that amendments to the Grid Code could be used to provide this information.

6.25 The option would have the implementation issues associated with illustrative option 1, plus additional changes. The delivery of TEC by a fixed date would require changes to CUSC and to associated bilateral agreements. To implement a system of bilateral trading, changes to the CUSC may be required and, in the event that trading generated revenues to the intermediary, it may be necessary to consider how these would be dealt with.

Illustrative option 4

6.26 The fourth illustrative option is based on option 3 and introduces an enduring financial commitment in return for TEC to all user. It involves:

- **'Local FSL**' – the new user is required to post security in line with the (periodically updated) profile of estimated costs of the local works only.

- **'TEC in 3 years for new, and a five year charging commitment for all'**. The new user would be allocated TEC not more than three years after he signed a contract committing him to pay for TEC (at the prevailing level of charges, and subject to the completion of local works) for a period not less the five years. All users with TEC would be obliged to provide security against an estimate of use of system charges for their level of TEC over a forward-looking five year period.

- **'Less-firm rights'** – a new product (or products) would be made available by National Grid in advance of TEC being available which provided users with a minimum volume of generation capacity over a specified period and had associated restrictions on the amount of compensation that would be paid in some circumstances.

- **Facilitated trading** – A party would act as a trading agent, publishing exchange rates and aiming to match parties seeking to purchase capacity with those willing to offer it for sale.

6.27 This option would involve more extensive change than any of the previous options but would result in consistent treatment of new and existing users.

6.28 As with previous options, the option involves a transfer of risk from new users to National Grid (and other licensees) in the event that works could not be delivered in the necessary timescales. There may therefore be a need for Ofgem to consider how licensees should be rewarded or remunerated for managing this increased risk.

6.29 The option might be expected to improve (relative to today) the quality of information on the demand for future capacity from both new and existing parties at the investment stage. The approach would generate information on both new demands for capacity and, were a party to decline to post security for a period, when existing capacity would be made available. This may be expected to allow more efficient investment decisions.

6.30 The material financial commitment by new users should act as a filter for projects currently in the queue and the option, as with those detailed above, will also provide greater certainty for new parties on when they will receive their TEC and what their liabilities will be before and after that date; potentially addressing some of the issues raised in the context of competition.

6.31 Implementing such an option would be expected to require similar changes to option 3. Changes to the CUSC and Bilateral agreements to require delivery by a fixed date may be required and further CUSC changes would be required to create a system of facilitated trading. In addition, National Grid would need to change the FSL methodology and Ofgem would need to consider how licensees should be remunerated or rewarded for bearing increased risk.

	FACILITATING MARKET ENTRY				INCREASING FLEXIBILITY IN METHODS OF GAINING ACCESS		FACILITATING EFFICIENT INVESTMENT		PROTECTING CONSUMERS FROM ADDITIONAL RISK		ADDRESSING THE QUEUE FOR CAPACITY	
	Reduced Volatility of FSL?	***Certain timing of FSL?***	***Reduced level of FSL?***	***Certainty of delivery?***	***Greater range of products?***	***Greater trading opps?***	***Better information from new entrants?***	***Certainty of info from incumbents?***	***More unsecured risk?***	***Greater ongoing commitment?***	***Larger commitment?***	***Incentives to speculatively apply?***
Status Quo				Contingent on consents	Limited (STTEC/ LDTEC)	Limited (CAP 068)	1 year commitment	Capacity reduction at 5 days notice	All with new entrant		No commitment pre FSL	Yes
Option 1	✓✓✓ Volatility removed	✓✓✓ Via date stamping	×	✓✓✓ Contingent on consents	✓ Possibly	✓ Possibly	× No increase	× No increase	✓ Limited transfer to TOs	×	×	✓ Reduced because of certainty of delivery
Option 2	✓✓ Local works less volatile	✓ Lower so may be more certain	✓✓ Only local works covered	✓✓✓ 3 years from completion of local	✓ Possibly	✓ Possibly	✓✓ 5 year commitment	× No increase	✓✓✓ All wider works	✓✓ 5 years of TNUoS upfront from new users	✓✓✓ No less than 5 years TNUoS in advance	✓✓✓ Much reduced – Large commitment + certainty of

				works								delivery
Option 3	✓✓ Local works less volatile	✓ Lower so may be more certain	✓✓ Only local works covered	✓✓✓ 3 years from completion of local works	✓✓ Non firm products developed	✓✓ Trading agent appointed	✓✓ 5 year commitment upfront	✗ No increase	✓✓✓ All wider works	✓✓ 5 years TNUoS upfront from new users	✓✓✓ No less than 5 years TNUoS in advance	✓✓✓ Much reduced – Large commitment + certainty of delivery
Option 4	✓✓ Local works less volatile	✓ Lower so may be more certain	✓✓ Only local works covered	✓✓✓ 3 years from completion of local works	✓✓ Non firm products developed	✓✓ Trading agent appointed	✓✓ 5 year ongoing commitment	✓✓ 5 year ongoing commitment	✓✓✓ All wider works	✓✓✓ 5 years ongoing commitment from all users – gives disconnection information.	✓✓✓ No less than 5 years TNUoS in advance	✓✓✓ Much reduced – Large commitment + certainty of delivery

Appendix 1 - Group Members

Ofgem

Colin Sausman (Chair)

Mark Copley

David Hunt

Sundeep Klair

Industry

Robert Longden – Airtricity

Malcolm Taylor – Association of Electricity Producers

Richard Ford – British Wind Energy Association

John Capener – British Energy

Danielle Lane – Centrica

Rupert Judson – EDF Energy

Paul Jones – E.ON

Simon Lord – First Hydro Company

Nick Pittarello, Adam Brown – National Grid

Terry Ballard – RWE npower

David Densley – Scottish Hydro Electric Transmission

Jim McOmish – Scottish Power Transmission

Keith Miller – Teeside Power

Mike Davies - Wind Energy

Mark Petterson – Warwick Energy

Appendix 2 – Terms of Reference

Objectives for electricity incentive development

2.1 Any models presented at the ARODG should be assessed against their ability to meet the objectives identified below. These are:

- Promotion of competition. The arrangements should promote competition between industry participants, where possible facilitating market entry.
- Efficient network development. Transmission companies should have incentives to optimise the use of existing capacity. In addition, demands for capacity should be appropriately signalled, ensuring that transmission licensees have sufficient information to efficiently allocate and provide capacity.
- Rewarding focused and timely delivery. Licensees should be rewarded for responding dynamically to changing circumstances to develop their networks in an economic, efficient and coordinated manner.
- Appropriate allocation of risk. Risk should be allocated appropriately between transmission companies, network users and consumers, and the rewards available to transmission companies should be appropriate to the risks they face.
- Simplicity and transparency. Access arrangements and associated incentives should form a coherent whole, recognising interactions between different aspects of transmission policy, and should be capable of being implemented as simply and transparently as practicable.
- Preventing undue discrimination. The mechanisms developed should prevent undue discrimination between classes of users.
- Minimising implementation costs. The arrangements should not impose undue implementation or administrative costs on industry participants, recognising that such costs might be expected ultimately to be passed on to consumer.
- Compliance with applicable legal requirements. Such as those within the Electricity Act, the Energy Act and relevant European law.
- Promoting social and environmental objectives. Any proposals should be consistent with Ofgem's wider statutory duties, reflecting the direct impacts that the transmission systems have on the environment, as well as the role the transmission systems play in facilitating broader social and environmental objectives.

Scope

2.2 The scope of the matters for consideration by the ARODG is confined to those relating to potential amendments to the existing transmission access arrangements and the associated development of necessary incentives consistent with the objectives identified above. The scope shall include the potential for the development of a range of models for amending the existing mechanisms for allocating transmission access rights and

associated financial commitments from users before, during and after construction. The Group will consider the potential costs of implementing any model and associated amendments to industry codes or licences.

2.3 It is important to note that the group is a development group and not a decision making body. In particular, nothing presented or discussed at the group can have the effect of fettering the Authority's discretion in relation to any decisions it takes on transmission access or wider electricity incentive issues.

Terms of reference

2.4 Consider and comment on any proposal brought forward by a member of the group, including TOs and Ofgem, in regard to the extent to which they would:

- Deliver against National Grid, SPTL and SHETL's licence conditions
- Deliver against the identified objectives
- Impact upon other industry codes, licences or associated aspects of electricity transmission or distribution policy. In particular consider interactions where incentives on transmission licensees may need to be developed.
- Benefit from refinement and enhancement by the Group.
- Where appropriate, identify and discuss potential alternative proposals and the extent to which they would:
- Deliver against National Grid, SPTL and SHETL's licence conditions
- Deliver against the identified objectives
- Impact upon the other parts of the regime or require the consequential development of incentives on transmission licensees.

Deliverables

2.5 Develop a range of 'straw-men' identifying changes to access arrangements. The key objective of the group is the development of a range of straw men identifying potential changes to access arrangements. This process will require quantification of the costs and benefits to be gained from access reform, and the identification of associated changes to industry codes or the need for contingent incentives. Any straw men developed by the Group should be analysed and critiqued by the working group such that they may pave the way for code modifications and amendments.

2.6 Access related incentives. Depending on the detail of any straw-men, there may be a need for contingent incentives to support the access regime (for example relating to the timely delivery of capacity). The group, in conjunction with Ofgem, should develop the key principles and high level mechanics of any such schemes.

2.7 Publication of group findings. Detail of the working group's discussions, straw-men and findings will be made public via Ofgem's website.

Appendix 3 – Glossary

A

The Authority/ Ofgem

Ofgem is the Office of the Gas and Electricity Markets, which supports the Gas and Electricity Markets Authority (GEMA), the body established by section 1 of the Utilities Act 2000 to regulate the gas and electricity markets in GB.

B

Balancing Mechanism

The mechanism for the making and acceptance of offers and bids pursuant to the arrangements contained in the BSC.

Bid

A bid is a tool used by the GBSO in the Balancing Mechanism, whereby a user submits data representing its willingness to reduce generation or increase demand. National Grid then decides whether or not to accept the bid.

Bilateral Connection Agreement (BCA)

An agreement between the licensee and a CUSC user relating to a direct connection to the GB transmission system identifying the relevant connection site and setting out other site-specific details in relation to that connection to the GB transmission system.

British Electricity Trading and Transmission Arrangements (BETTA)

The arrangements for the trading and transmission of electricity across Great Britain which are provided for by Chapter 1 of Part 3 of the Energy Act 2004, which have replaced the separate trading and transmission arrangements which existed prior to 1 April 2005 in Scotland and in England and Wales.

Balancing Services Use of System Charges (BSUoS)

The charges levied by National Grid in respect of the activities it undertakes to keep the transmission system in electrical balance at all time.

C

Clustering

Clustering is the process adopted by National Grid to identify and undertake reinforcements which impact one or more Users, where consideration is given to groups of generators not individuals

Connection Entry Capacity (CEC)

A measure of the maximum capability, expressed in MW, of a connection site and the associated generation units' connection to the transmission system.

Connection and Use of System Code (CUSC)

Multi-party document creating contractual obligations among and between all users of the GB transmission system, parties connected to the GB transmission system and National Grid is relation to their connection to and use of the transmission system.

Consents

The process of obtaining Consents for the construction of a new overhead line to serve, for example, a wind farm can essentially be broken down into two distinct areas. Consents to be obtained from the Secretary of State/ Planning authorities etc in relation to permission allowing a line to be built and secondly, and more practically, consents from landowners who will be effected by the construction of the new line.

For a new line consent under section 37 of the 1989 Act will be required. Inevitably proposals for a new line will be subject to a public inquiry. It is possible that recent changes in the regulations governing the conduct of inquiry in England and Wales may assist the process by reducing the requirement to justify the need for the line. Whether or not this proves to be the case, site specific issues such as those raised by statutory consultees (including local planning authorities, English Nature, English Heritage or the Environment Agency) or local residents take up a great deal of time at any inquiry. It is unlikely that any reduction on time spent justifying the need for the line will have a significant impact on the overall duration of the process.

In addition to section 37 consent, the DNO/TO must also obtain consent from the landowners over whose land the line will run. If a voluntary agreement cannot be struck, then either the land will have to be compulsory purchased, under the provisions of section 10 and Schedule 3 (which is usually used for substations), or a Necessary Wayleave obtained over it, under the provisions of section 10 (Schedule 4 paragraphs 6-8). Both the Compulsory Purchase Order process and the Necessary Wayleave process can take a significant amount of time.

Constraints

In the event that the pattern of generation may exceed the safe operational limits of a particular line or transmission system equipment, the GBSO will take actions to reduce the output of generators at specific locations on the system. At present these actions are taken in the Balancing Mechanism in the form of bids, and also via ancillary services, such as Pre-Gate Closure Balancing Mechanism Unit Transactions (PGBTs). Where a user's output is constrained down at a point on the system, the overall balance of energy will need to be retained, and costs will be incurred by the GBSO in bringing replacement energy onto the system.

Contracted background

This is the planning background against which NGET assesses applications for connection and use of system. The contracted background includes all users that have entered into an (ongoing) agreement with NGET for connection or use of system.

D

Deep reinforcement

Deep reinforcement refers to the works conducted on the wider transmission system in order to accommodate a change in the generation and demand pattern.

Direct Current Load Flow (DCLF)

A standard technique used by electrical engineers to model electrical flows across a network. National Grid use a DCLF ICRP (see definition below) transport model to calculate how much extra transmission capacity is required to accommodate extra generation being put on the network at each point of the network.

Distributed Generation

A generator directly connected to a distribution system or the system of another user.

E

Evergreen

In the context of access rights, evergreen relates to access rights that do not have a finite end date.

F

Final Sums Liabilities

The calculation of securities required for Users for their own works and for works that they will share with other Users.

G

GB System Operator (GBSO)

The entity responsible for operating the GB transmission system and for entering into contracts with those who want to connect to and/or use the GB transmission system. National Grid is the GB system operator.

GB Transmission System

The system of high voltage electric lines providing for the bulk transfer of electricity across Great Britain.

GB Transmission Use of System Charging Methodology

The methodology which National Grid is required to have in place by its transmission licence and which is used to calculate the charges to customers for use of the GB transmission system. The GB transmission use of system charging methodology is in practice comprised of two separate methodologies – a BSUoS charging methodology (defined above) and a TNUoS charging methodology (defined below).

Grid Code

A document prepared by the transmission licensee in accordance with Standard Licence Condition C14 of the Transmission Licence setting out the technical parameters for the operation and use of the transmission system and of plant and apparatus connected to the transmission system.

H

H1 Sole Works

These are the works that are only required for a specific user, but are charged via TNUoS charges as infrastructure. The User's liability will relate to the costs estimated to be incurred in respect of the cancellation of such works in that 6 month period.

H1 Shared Works

Shared reinforcement works are identified as being required for a number of Users. Where a clustering approach has been used then the Users in that cluster will share the liability for the works concerned. However, there will be cases where using an incremental approach to system design reinforcements will be identified that benefit multiple Users and in such cases those Users will share the liability for the works concerned.

The Users' liabilities are for the costs estimated to be incurred for the shared works to be undertaken during the following 12 month period that commences at the start of that security period. For example, for the period April to the end of September, Users would be liable for the costs incurred during the following 12 months, i.e. 1st April to the 31st March.

H2 Works

The H2 Wider Reinforcement Works notify the User of other works that are required to meet their connection date. However, the User is not financially liable for these works as 24 March 2006 they will generally be included in other Users H1 Works.

It is possible that these H2 works for which the User is not currently financially liable could subsequently be transferred into the H1 Appendix in the event of a change in the contracted background.

I

Interactive

An interactive offer is an offer for connection or use of the GB transmission system which, if accepted, would affect the terms of another offer for connection or use of the GB transmission system. CUSC 6.10.4 sets out the process National Grid follows where offers are interactive, ie conditional upon one or more other offers.

Interruptible Products

Products which allow National Grid to remove the right to generate prior to a given point at zero (or a reduced) cost.

Investment Cost Related Pricing (ICRP)

A means of setting charges which seeks to link the charge paid for a particular service (such as use of an electricity transmission network) to the cost of the investment (in the network) required to provide that service.

K

Kilowatt (kW)/ Megawatt (MW)

A kW is the standard unit of electricity, roughly equivalent to the power output of a one-bar electric fire. A MW is a thousand kilowatts.

L

Limited Duration Transmission Entry Capacity (LDTEC)

LDTEC is a firm capacity product, which is provided within the financial year. It can provide access for a maximum of one financial year, and does not confer additional rights beyond the end point of the product. The availability of LDTEC would be assessed against operational criteria according to a pre-defined timetable that would provide access within three weeks from National Grid's receipt of an application.

Local works

Those works required to provide a generator with a connection to the transmission network that would allow it to export power. These works include all of H1 sole and may include part of the H1 shared works.

O

Offer

An offer is a tool used by the GBSO in the Balancing Mechanism, whereby a user submits data parameterising its willingness to increase generation or reduce demand. National Grid then decides whether or not to accept the offer.

Operating Code 2 (OC2)

Operating Code 2 is a chapter of the Grid Code, relating to Operational Planning and Data Provision.

R

Regulatory Asset Value (RAV)

The value ascribed by Ofgem to be the capital employed in the licensee's regulated transmission or (as the case may be) the distribution business (the 'regulated asset base'). The RAV is calculated by summing an estimate of the initial market value of each licensee's regulated asset base at privatisation and all subsequent allowed additions to it at historical cost, and deducting annual depreciation amounts calculated in accordance with established regulatory methods. These vary between classes of licensee. A deduction is also made in certain cases to reflect the value realised from the disposal of assets comprised in the regulatory asset base. The RAV is indexed to RPI in order to allow for the effects of inflation on the licensee's capital stock. The revenues licensees are allowed to earn under their price controls include allowances for the regulatory depreciation and also for the return investors are estimated to require in providing the capital.

S

Short Term Transmission Entry Capacity (STTEC)

STTEC is a firm capacity provided, provided within-year, in 4, 5 or 6 week blocks.

System Operator - Transmission Owner Code (STC)

The document which sets out the terms between the transmission licensees whereby the GB transmission system is planned, developed and operated and transmission services are provided.

T

Transitional Arrangements

Arrangements that may be devised and implemented to provide a bridge between existing arrangements and more enduring arrangements.

Transmission Asset Owner (TO)

There are three separate transmission systems in Great Britain, owned by three Transmission Asset Owners, National Grid Electricity Transmission plc, Scottish Hydro Electric Transmission Ltd and Scottish Power Transmission Ltd. National Grid also has the role of system across the whole of Great Britain.

Transmission Entry Capacity (TEC)

The contracted maximum amount of electricity that each user is permitted to export on to the GB transmission system at any given time.

Transmission Network Use of System (TNUoS) charges

Charges that allow National Grid to recover the costs of providing and maintaining the assets that constitute the GB transmission system.