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TRANSMISSION ACCESS REVIEW - STRAW MAN CREATION

A report to BERR/Ofgem

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1. INTRODUCTION

1.1 Purpose of this document

The purpose of this document is to set out and describe viable straw man models for transmission access arrangements in GB. Pöyry was commissioned to undertake this work by BERR/Ofgem as part of the Transmission Access Review (TAR) process. As qualitative and quantitative assessment of straw man models will form the next phase of the TAR, this document does not seek to assess the straw man models outlined within it.

The development of viable straw man models builds upon work already undertaken by Pöyry for BERR/Ofgem as part of the TAR to identify and qualitatively assess individual transmission access building blocks[1]. A summary of this work is contained in Appendix 1 of the January 2008 interim report on TAR published jointly by Ofgem and BERR[2]. The straw man models described in this document follow the building block structure identified in that work, which was, in turn based upon the 'key generic features' of transmission access models identified by Ofgem at the seminar on 5 November 2007. Annex A contains a summary of the TAR building block options identified as part of our previous work for reference purposes.

1.2 Introduction to the straw man models

1.2.1 *Objective and drivers*

The original terms of reference for the TAR were set out in the July 2007 open letter[3], which stated that the objective of the TAR is: "*to support the delivery of the government's aspiration of 20% of electricity being supplied by renewable generation*".

For the purposes of this work, we have focused on the need for an increase in output from renewable generation in order to achieve this objective. However, the proposals put forward as part of the TAR also need to be consistent with the government's energy goals, which include putting the UK on a path to cut our carbon dioxide emissions by some 60% by about 2050, with real progress by 2020.

In light of these objectives, we identified four important drivers to be considered in the creation of any model of transmission access arrangements as part of TAR. As these drivers are to some extent competing aims, Figure 1 describes how each straw man model is intended to strike a different balance between them. However, Figure 1 is not intended to represent in any way an assessment of the performance of the models against each driver.

The drivers are discussed in detail in the sections below.

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1 Reference: "TAR Building Blocks & Options", version 3_0, Pöyry Energy Consulting, 18 December 2007

2 Reference: "Transmission Access Review – Interim report', BERR/Ofgem, January 2008

3 Reference: 'Transmission Access Review (TAR) – Open Letter to Industry', BERR/Ofgem, July 2007

1.2.1.1 Driver A: Ensure rights to generate are distributed efficiently at the time of delivery

We consider that the current arrangements for the pricing of transmission access do not reflect the dynamic nature of the value of transmission capacity. Under the existing generation profile and access arrangements (in which transmission constraints are limited in extent), the use of long-term rather than short-term locational transmission pricing probably does not materially distort short-run incentives.

Increased penetration of more intermittent generation means that the value of transmission capacity for different users is likely to be highly dynamic compared to the present situation.

Determining factors for the value of transmission capacity include the availability of the network, patterns of demand and generation, notably the pattern of wind. With the expected increase in wind penetration to the generation mix, these factors will vary considerably over time, including within-day, and by location to a far greater extent than today. This suggests that the appropriate timing for valuing and (as required) trading/sharing of transmission capacity is close to (or after) real time, rather than significantly in advance.

We consider that it is beneficial to ensure that the parties who value access the most hold rights to generate at the time of delivery[4]. This would facilitate efficient (self-) dispatch decisions by generators and help to support competitive energy markets, particularly with respect to generation.

1.2.1.2 Driver B: Facilitate release of increased quantity of access rights

We consider that the existing transmission access regime appears not to facilitate the full use[5] of network capacity at all times, irrespective of the level of freedom with which Transmission Entry Capacity[6] (TEC)is re-traded after initial allocation. This is because the existing TEC allocation rules (which are long-term and contingency-dependent) do not make full use of information about system capability that is revealed close to real time, including within-day. Consequently, there are occasions when additional access could be accommodated, over and above the capacity released under the existing processes for allocating entry capacity. Although there are existing provisions for within-year release of firm capacity[7] and long-term release of non-firm capacity[8], the existing processes centre on the release of firm access rights at the year-ahead stage. As a consequence, a simple

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4 This is a less strong statement than saying that parties who value rights less (i.e. are ‘out of merit’, considering transmission constraints) should not hold rights on the day.

5 The precise definition of ‘full use’ of the network is debatable – ultimately this is an economic rather than a physical concept; for example the System Operator may have the ability to accommodate additional (low-cost) generation in one area by constraining off another (higher-cost) generator; allowing this ‘trade’ would be within our definition of making maximum use of the available capacity.

6 The level of Transmission Entry Capacity allocated to a user places a contractual ceiling on the amount of electricity that the user is permitted to export onto the GB transmission system at any given time.

7 Within-year firm products currently available include Short Term TEC (STTEC) and Limited Duration TEC (LDTEC)

8 Long-term non-firm products include interim TEC (ITEC) and TEC-lite.

redistribution of the existing quantity of rights would not maximise the use of the system and its ability to accommodate additional (renewable) generation.

We have concluded that an objective of revised arrangements should be to ensure that, on the day, total rights are at least equal to the actual system capability. Therefore, we consider that increased renewable generation may be facilitated by making additional access rights available, whether long-term or short-term, firm or non-firm (including overrun); and potentially based on users' willingness to pay for incremental capacity.

The models described in this report consider only one type of non-firm access product (other than overrun). We adopt an option for 'non-firm' products in which there are administered prices for any buy-back (in the Balancing Mechanism). Quantity-based models or non-firm access (e.g. where a user buys an interruptible right) have not been considered explicitly; we consider that the effect is similar to the version that we have considered (whereas we consider that overrun is another type of non-firm access right, in that the price is non-firm)[9].

1.2.1.3 Driver C: Mitigate constraint costs

The release of additional firm access rights beyond current levels is likely to be associated with an increase in the costs of managing system constraints. The design of the price control, incentive and network planning regimes means that the System Operator cannot directly trade-off the benefits of increased firm access sales against increased constraint and other operational costs. In addition constraint costs are smeared through the Balancing Services Use of System (BSUoS) charges[10] levied on transmission system users and ultimately passed to consumers. Therefore, mitigation of any additional constraint costs is likely to be an important factor in the assessment of any straw man option.

1.2.1.4 Driver D: All generators face the short-term value of transmission capacity at the margin

As discussed above, the value of transmission capacity is expected to vary more dynamically in future, with significant changes close to the time of delivery.

We therefore consider a fourth driver, which is that (to the maximum extent possible) **all** generators should at the margin face the short-term value of transmission capacity when making their trading and dispatch decisions. This might be achieved by highly liquid secondary trading of transmission access products close to real time, in the absence of barriers to effective trade (thus introducing an opportunity cost for the use of transmission capacity at the margin); or by other means.

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9 Under the release of non-firm capacity, the rights holder bears the risk of constraints. Under the release of firm capacity, the System Operator bears the risk of constraints (tempered by the design of the System Operator incentive scheme, in particular in relation to sharing factors, caps and collars). Under various types of non-firm capacity (such as administered price buy-back, interruptible rights or overrun), the risk remains with the rights holder rather than the System Operator.

10 The GBSO levies Balancing Services Use of System Charges in respect of the activities that it undertakes to keep the system in electrical balance at all time

1.3 Outline of the straw man models

1.3.1 Process of selection

The process for the definition of the four straw man models started with the production of a long list of possible options through a combination of the following:

- the options included within the TAR Call for Evidence[11] and the second TAR stakeholder workshop held on 5 November 2007 (as a starting point for internal discussion);
- coverage of the range of viable options, including the collective options, for each of the main decision 'building blocks' identified in the previous Pöyry work[12]; and
- capturing the links between building blocks that were described in the previous Pöyry work.

The long list consisted of seven candidate models, which are described in Annex B. In order to ensure that further assessment is targeted onto those areas where it is most worthwhile, this long list was then subjected to a review, refinement and selection process to ensure that there was no unnecessary duplication. This resulted in agreement between Pöyry, Ofgem and BERR on the four straw man models that would undergo further consideration.

1.3.2 Four straw man models identified

The four selected straw man models (one of which contains a variant) are as follows:

1. Full Connect and Manage (including a variant);
2. Limited Connect and Manage;
3. Market Based Access Allocation and Trading; and
4. Locational Transmission Charging with Tradable Financial Rights.

The following sections provide a brief outline of each of the models, including the principles underlying each of the four straw man models and the linkages to the drivers discussed above.

Sections 2 to 5 of the report include more detail of each of the models, including:

- a description of the model;
- an explanation outlining how and why the model is viable; and
- an indication of the main issues of relevance in terms of implementation of the model.

1.3.2.1 Full Connect and Manage (model plus variant)

The main principle underlying the Full Connect and Manage model is simply that additional transmission access and the associated connections should be facilitated to the maximum extent possible; an emphasis on drivers A and B above (explicitly at the expense of drivers C and D), increasing the availability of (firm) rights with little

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[11] Reference "Transmission Access Review - A Call for Evidence for a Review of Transmission Access"; BERR/Ofgem 16 August 2007. Reference (BERR) URN 07/1226, (Ofgem) 212/07.

[12] Reference: "TAR Building Blocks & Options", ibid.

consideration of short-term (or long-term) transmission value. As a consequence, the role of the planning standards in determining the timing of new connections and the granting of transmission access rights would be abolished, and additional connections and transmission access rights would be granted irrespective of whether deep reinforcement had been completed.

We have outlined a variant of the Full Connect and Manage model which requires any additional connections to facilitate increased renewable output[13]. Although this does not guarantee a positive cost-benefit trade-off, it seeks at least to ensure that there are benefits (in terms of ability to meet renewables targets) associated with each accelerated connection. The Full Connect and Manage model variant (1b) would thus have the effect of limiting the release of additional capacity (i.e. reducing the emphasis on driver A compared with option 1a), with a mitigating impact on constraint costs (driver C).

1.3.2.2 Limited Connect and Manage

The main principle underlying the Limited Connect and Manage model is that additional transmission access and the associated connections should be facilitated as far as may be accommodated by the operation of the transmission system in real time, through the issuing of 'non-firm' access rights. This is explicitly targeted at drivers B and C above; increasing rights while limiting constraint costs, and to a lesser extent driver A (with the distribution of non-firm rights).

1.3.2.3 Market Based Access Allocation and Trading

The 'Market Based Access Allocation and Trading' model is intended to facilitate trading of the existing allocated transmission capacity, while including flexibility in both the total quantity of firm rights allocated and the ability of generators to overrun their firm access rights. This is explicitly targeted at drivers A, B and C and to a lesser extent D above; increasing rights through incremental capacity auctions, short-term capacity release and overrun, and enhancing the ability to trade the allocations through the definition of the product and the existence of ex post trading.

1.3.2.4 Locational Transmission Charging with Tradable Financial Rights.

The design of the 'Locational Transmission Charging with Tradable Financial Rights' straw man seeks to ensure that additional generation would be accommodated to the maximum extent possible on each day (through the allowance of overrun), while limiting any associated increase in costs of constraint compensation payable to generators (since there would be no increase in firm access rights). The intention is that all participants face the short run costs of transmission access in each half hour in order to deliver efficient energy trading and (self)-dispatch decisions, while recognising the potential limitations[14] to bilateral trading of transmission access capacity close to real time[15]. This model is therefore targeted at drivers B, C and D and to a lesser extent A above[16].

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13 This could be amended to cover output of low-carbon generation if required.

14 For example, there may be high transaction costs associated with such trading.

15 The intended operation of this model is consistent with (rather than reliant on) an efficient secondary trading market close to real time.

16 Driver A is included to the extent that all users hold rights to generate at gate closure (as in the Full Connect and Manage models), but that the transmission pricing (if it works in a theoretically correct manner) provides incentives for users to generate in a way which is consistent with transmission constraints, consistent with the (local) merit order.

The four selected straw man options will permit further evaluation of a wide range of choices in a manageable way. However, the list of straw man options is non-exhaustive and has not been informed by modelling or other quantitative analysis (in developing these models, Pöyry has not been asked to provide any assessment as to the relative merits of each). The production of straw man options is designed to highlight the key design features of a mechanism for transmission access. It is intended to facilitate comparison of different options; in many cases, we have included two extreme alternatives rather than the potential compromises between them. This process does not preclude the final arrangements from being based on a combination of different (or even additional) straw man models; there are several components of a revised access regime which could usefully apply to a number of the models.

Figure 1 highlights the intended drivers behind each of the straw man models. It does not reflect the results of an assessment of the outcomes of the models.

Figure 1 – Intended drivers of the four straw man models

	A Ensure rights to generate are distributed efficiently at the time of delivery	B Release of increased quantity of access rights	C Mitigate constraint costs	D All generators face the short-term value of transmission capacity at the margin
1a - Full Connect and Manage				
1b - Full Connect and Manage (renewables)				
2 - Limited Connect and Manage				
3 - Market based access allocation and trading				
4 - Locational Transmission Charging with Tradable Financial Rights				

Source: Pöyry Energy Consulting

1.3.3 Common assumptions for all models

There are a number of 'framing' assumptions in relation to each of the elements that are used to build up the straw man models. These assumptions, which are set out below, are consistent with those applied in the previously completed 'TAR building block' work[17]. These assumptions are common across all the straw man models described in this report.

1.3.3.1 Definition of rights

Given the heavily meshed nature of the GB transmission system, access rights are defined in the context of an entry-exit model, rather than flowgate or point-to-point rights.

It is assumed that demand access rights will continue to be treated implicitly. Therefore, the focus is on entry rights for generators only. The treatment of distribution-connected generators is not explicitly discussed, but within these models it is assumed that they will

[17] Reference: "TAR Building Blocks & Options", ibid.

continue to face either explicit or implicit rights (as at present) depending on their circumstances[18].

The transmission access arrangements currently include a set of flexible products which complement the core Transmission Entry Capacity (TEC) product for transmission access. These products include firm capacity released within-year and long-term non-firm capacity, although their take-up has been rather limited to date. We believe that, subject to further assessment of specific options, any reformed arrangements should deliver an increase in the range, availability and/or take-up of flexible products compared to the present arrangements.

We have assumed that the present physical/financial nature of firm access rights will remain unchanged in the sense that holders of firm access rights do not have a guarantee they will actually be able to generate. However, their firm right provides them with a right to financial payments with the trigger for this payment stream varying across the different models[19].

We have assumed that entry and capacity will continue to be treated separately for long-term firm access rights and bilateral trading. This would facilitate trading of spot energy in a liquid GB-wide market.

As at present, the exception to this separation is balancing actions taken by the SO, in the form of either Balancing Mechanism trades or Pre-Gate Balancing Transactions (PGBTs), in which the SO may curtail users' transmission access through trades which encompass energy.

1.3.3.2 Allocation of rights

We assume that any revised access right allocation mechanism would not result in a decrease in the aggregate quantity of firm access rights allocated compared to current (or committed) levels. Therefore, the aggregate quantity of TEC currently committed is assumed to provide a floor for the quantity of firm access rights allocated.

1.3.3.3 Pricing of rights

We have assumed that the primary source of network revenue will remain some form of long-term marginal cost-based pricing. This is the case under each of our four straw man models, including the fourth option in which long-term financial transmission rights are offered to participants.

1.3.3.4 Trading of rights

We assume that trading of access rights will be possible at least to the extent possible under the existing arrangements. In recent years, CUSC modification proposals have led

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18 It is assumed that where distributed generation is treated as generation or demand currently it will continue to be treated as generation or demand respectively. The exact treatment of Bilateral Embedded Generation Agreements (BEGA) and Bilateral Embedded Licence Exemptable Large Power Station Agreements (BELLA) will need explicit consideration during assessment and implementation phases.

19 In the fourth straw man option ‘Locational Transmission Charging with Tradable Financial Rights’, the access rights become entirely financial in nature, ceasing to relate to physical delivery.

to the introduction of arrangements for the permanent[20] and temporary[21] exchange of TEC. There has been fairly limited take-up of these opportunities for trading so far.

All trades of capacity rights within the area over which the product is defined (e.g. intra-zonal) are permitted at an exchange rate of 1:1. This implies that SO approval is not required for such trades.

1.3.4 Implementation issues

There are a number of dimensions to the consideration of the implementation of any of the straw man models described in this report.

1.3.4.1 Changes to core industry documents

The first dimension to implementation relates to the fact that each of the straw man models set out here requires change across a suite of core industry documents. Therefore, cross-code governance issues must be addressed (or circumvented) in the implementation process irrespective of which approach is taken forward.

For example, each of the straw man models considered may require changes to:

- the allocation and definition of transmission access rights;
- the mechanics by which generators may gain access;
- the mechanics by which the System Operator may change generators' preferred dispatch;
- the charging mechanisms for transmission access; and
- the various incentives placed upon the transmission owners and operators by their respective Price Control and System Operator Incentive schemes.

In terms of changes to industry documentation, this is likely to affect at least the Balancing and Settlement Code (BSC), the Connection and Use of System Code (CUSC) and the Grid Code; and potentially the charging mechanisms for balancing costs, the Transmission Owner and System Operator Price Control and System Operator Incentives, and the underpinning licence regime. We anticipate that the extent to which such changes are required will form part of the further assessment of each of the models.

1.4 Structure of this document

The remainder of this document is structured as follows:

- Section 2 relates to a 'Full Connect and Manage' model plus a variant;
- Section 3 relates to a 'Limited Connect and Manage' model;
- Section 4 relates to a model termed 'Market Based Access Allocation and Trading';
- Section 5 relates to a model based upon and referred to as 'Locational Transmission Charging with Tradable Financial Rights';

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20 CAP068 ('Competing Requests for TEC') facilitated arrangements whereby generators are able to permanently trade TEC rights in line with an exchange rate set by the System Operator.

21 CAP142 ('Temporary TEC Exchanges') introduced opportunities for trading of TEC over periods of between four and 42 weeks in duration.

- Section 6 presents a summary of the straw man models;
- Annex A provides a summary of the TAR building block options from our previous work; and
- Annex B sets out the seven candidate models from which the four straw man models were created.

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2. FULL CONNECT AND MANAGE

2.1 Introduction

This section relates to the 'Full Connect and Manage' straw man model plus one variant.

2.1.1 Principles underpinning 'Full Connect and Manage' models

The main principle underlying the Full Connect and Manage models is simply that additional transmission access and the associated connections should be facilitated to the maximum extent possible; an emphasis on drivers A and B above[22] (explicitly at the expense of drivers C and D)[23], increasing the availability of (firm) rights with little consideration of short-term value. As a consequence, the role of the planning standards in determining the timing of new connections and the granting of fully financially firm transmission access rights would be abolished, and additional connections and transmission access would be granted to eligible applications irrespective of whether deep reinforcement had been completed. However, the granting of access rights would remain subject to the completion of local works.

We have outlined a variant of the Full Connect and Manage model which requires any additional connections to facilitate increased renewable output[24]. Although this does not guarantee a positive cost-benefit trade-off, it seeks at least to ensure that there are benefits (in terms of ability to meet renewables targets) associated with each accelerated connection. The Full Connect and Manage model variant (1b) would have the effect of limiting the release of additional capacity (reducing the emphasis on driver A compared with option 1a), with a mitigating impact on constraint costs (driver C).

Charging for the additional firm rights granted under this model would use the existing long-run-incremental charging regime, i.e. without levying transmission charges which reflect the short term scarcity of the additional access granted.

The Full Connect and Manage model and variant both focus on directly increasing the quantity of firm access rights allocated to renewable generation. They are consistent with the objective of the recently published proposal for a Renewables Directive[25] intended to promote the use of energy from renewable sources. The proposal states that transmission System Operators and distribution System Operators shall provide for priority access to the grid of electricity produced from renewable energy sources.

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22 See section 1.2.1 above for an explanation of the four model drivers:
- A: Ensure rights to generate are distributed efficiently at the time of delivery
- B: Facilitate release of increased quantity of access rights
- C: Mitigate constraint costs
- D: All generators face the short-term value of transmission capacity at the margin.

23 The variant "Full Connect and Manage" option (1b) would have the effect of limiting the release of additional capacity, with a mitigating impact on driver C.

24 This could be amended to cover output of low-carbon generation if required.

25 Proposal for Directive 'Promotion of the use of energy from renewable sources'. See: http://ec.europa.eu/energy/climate_actions/doc/2008_res_directive_en.pdf

2.2 Description of the straw man

Figure 3 provides an outline of the design features associated with the Full Connect and Manage model and its variant. This model is broadly consistent[26] with the 'connect and manage' collective option (C1b) described in our previous work[27] to assess the building blocks of potential models for transmission access arrangements (see Annex A for an overview of our previous work).

[26] The only difference is in variant 1a when incumbents are not explicitly prioritised. However, as they effectively retain their existing rights, the effect is the same as whether the incumbents are prioritised or not.

[27] Reference: "TAR Building Blocks & Options", ibid.

Figure 2 – Full Connect and Manage Straw Man

Definition of rights

Common assumptions for all models

- Entry-exit system
- Entry rights only, demand treated implicitly
- Capacity kept separate from energy market

Model features

- Nodal rights (D1a)
- Asymmetric, indefinite rights (D2a)
- Long-term, fully financially firm rights (D3a)

Allocation of rights

Common assumptions for all models

- Aggregate quantity of firm rights will not be lower than at present

Model features (1a)

- Rights delivered based on eligible requirements (A1b)
- Incumbents not prioritised (A2b) – all equal

Variant features (1b)

- Rights for non-renewables delivered based on system capability (A1a)
- Additional rights for renewables delivered based on eligible requirements conditional on impact on renewable deployment (A1b)
- Prioritise incumbents (A2a)

Pricing of rights

Common assumptions for all models

- LRMC remains the primary source of revenue for the TO

Model features

- LRMC-based pricing (P1a)

Trading of rights

Common assumptions for all models

- Some form of trading will be possible at least in line with current trading
- Trading of rights within the same geographically defined area can be done at an exchange rate of 1:1

Model features

- Trading of SO defined products (T1a)
- Trading before Gate Closure (T2a)
- SO provides exchange rate on application (T3a)

Source: Pöyry Energy Consulting

2.2.1 Definition of rights

Access rights are defined with reference to a particular node. They are indefinite in nature with no fixed end-point, meaning that a right is open ended and only ceases to apply when the holder opts to relinquish it. The obligations upon the System Operator and the holder are asymmetric in nature, with the holder having relatively 'short' commitments while the System Operator has 'long' commitments. The holder's commitment is short insofar as it only has to provide a short notice period in the event that it wishes to relinquish its rights and it only has to pay for access on a rolling annual basis. The System Operator's commitment is long as it has to honour an access right holder's long-term rights, with renewal rights conferred so long as transmission network charges are paid. At a high-level, this is consistent with the current arrangements for the duration and symmetry of access rights, subject to CUSC modifications.

The model and variant both include long-term, financially firm access rights. This requires the holder to pay for the right, as mentioned above. It also means that the System Operator must provide market based financial compensation payments (e.g. through Balancing Mechanism bid payments) to the holder in the event that a generator's requirement for physical access cannot be accommodated in delivery timescales.

2.2.2 Allocation of rights

2.2.2.1 Full Connect and Manage Model (1a)

Under the Full Connect and Manage model, there is no system capability restriction on the quantity of firm access rights to be allocated. The quantity of firm access rights allocated is instead driven by eligible demand for access by generators to match their requirements.

The rights of existing users are not explicitly prioritised under this model. However, as rights are allocated to match eligible requirements (subject to timing), existing users are effectively able to preserve their current rights as it is expected that they would be able to satisfy any proposed requirements for eligibility.

As discussed above, long-term firm access rights would be issued to satisfy eligible demand from all existing and new generators. Therefore, the model does not focus on extending existing mechanisms for the allocation or redistribution of firm rights close to or after the time of delivery. This means that the concepts of long-term non-firm rights, short-term firm rights and overrun do not form part of this model.

2.2.2.2 Full Connect and Manage Variant (1b)

Variant 1b of the Full Connect and Manage model preserves existing users' rights, which are allocated in line with overall system capability (subject to planning and contingency requirements). However, firm access rights are allocated to renewable generation over and above (planning) system capability to match requirements. This is subject to a restriction that allocation of additional firm access rights increases overall renewable output[28] and so does not simply result in the displacement of existing renewable generation.[29]

As discussed above, long-term firm access rights would, under variant 1b, be issued to satisfy eligible demand from all generators whose connection would increase the amount

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28 This condition could be relaxed whereby additional firm access rights could only be allocated if it does not reduce the overall level of renewable generation available. This would enable thermal generation to be covered by 'Connect and Manage' in cases where it would not displace renewable generation.

29 Another option would be for Variant 1b to apply to low carbon generation, rather than just renewable generation. This could enable, for example, nuclear or fossil fuel plus carbon capture and storage generation to be covered. The potential application of variant 1b to low carbon generation is consistent with the overall aims of the TAR (as set out in section 1.2.1 above) given the emphasis of government energy policy on reducing carbon dioxide emissions.

of renewable output. The variant does not focus on extending existing mechanisms for the allocation or redistribution of firm rights close to or after the time of delivery.

2.2.3 Pricing of rights

The price of the long-term firm access rights within both the Full Connect and Manage model and its variant is determined ex-ante based upon a long-run marginal cost-based (LRMC) methodology, as at present.

2.2.4 Trading of rights

Under both the model and its variant, long-term firm access rights would be issued to at least satisfy eligible demand from all generators whose connection would increase the amount of renewable deployment. Therefore, these models retain rather than extend the existing arrangements for secondary trading of access rights.

For the purpose of trading, access rights can be disaggregated to the level permitted by the System Operator. All trading must occur before Gate Closure. The exchange rate for trading (between the different nodes at which access is conferred) is specified by the System Operator upon application.

2.3 Viability/internal consistency of the straw man

The primary driver of the Full Connect and Manage options is to directly increase the quantity of firm rights allocated to renewable generation. Therefore, the model does not also include other design features which were identified in the previous Pöyry work as potentially facilitating the reallocation of existing rights to renewable generators. This is because the inclusion of these features in this model and variant may lead to increased cost and complexity without creating any additional benefit in terms of increased firm rights for renewable generators. Such design features include more extensive allocation or redistribution of firm rights close to real time or secondary trading arrangements. Therefore, taking our previous work in relation to transmission access building blocks as a starting point, this section discusses the key interactions between the design features chosen at each decision point.

2.3.1 Indefinite, asymmetric nodal rights and trading

The models do not seek to facilitate increased trading of access rights. This is compatible with the retention of access rights that are defined at a nodal level, which may hinder trading either across or between the portfolio of connected parties. For example, the pre-publication of exchange rates is made more complex by a system of nodally-defined rights as there are a much larger combinations of potential trades. In addition, an ‘indefinite’ and ‘asymmetric’ definition of access rights means that there is less incentive for generators to dispose of ‘redundant’ rights.

2.3.2 Nodal rights and indefinite duration of access rights

Nodal rights do not need to be redefined over time to reflect prevailing generation and demand patterns, as is potentially the case for zonal rights. Nodal rights can, therefore, be defined on an indefinite basis.

2.3.3 Definition of rights, LRMC-based pricing and prioritisation of incumbents

The retention of rights that are broadly consistent in terms of geographical scope, pricing, duration and symmetry with existing rights means that there are no transition issues with respect to prioritising incumbents as the high-level nature of the right that they hold is unchanged.

2.4 Main issues for implementation/development

There remain a number of implementation/development issues that would need to be addressed during the consideration of more detailed arrangements based on the Full Connect and Manage model and variant.

One of the main issues is determining the conditions and timescale under which firm access rights are granted. As the link to network planning standards has been removed, new eligibility criteria will need to be established. As far as is appropriate, the grounds for eligibility should be consistent with the queue management procedures being developed by National Grid. Following the publication of a final conclusions report on queue management in June 2007, National Grid is currently preparing a more detailed methodology for publication. In addition, the definition and prioritisation of eligible demand is currently under review in industry governance processes, with CAP148 (Deemed Access Rights to the GB Transmission System for Renewable Generation) being one example of recent proposals in this area. Therefore, the implementation phase of the Full Connect and Manage options would need to consider any developments in relation to the definition and prioritisation of eligible demand that emerge from industry workstreams and/or governance processes.

The grounds for eligibility may link to the achievement by the generator of particular defined milestones, for example the access right may be granted as soon as the station is ready to be operational and local works have been completed. Linking the release of access to a physical milestone such as this would also reduce the incentive for speculative applications. Alternatively, access may be granted after a delay of specified length following a specified trigger, such as the signing of a connection agreement. This would allow the System Operator time to undertake actions designed to mitigate future constraint costs (although the period may not be long enough to allow the System Operator to complete deep system reinforcement that would eliminate the constraint costs associated with the connection). For example, this may include access being granted a maximum of 3 years after the signing of the connection agreement, subject to completion of local works. A longer time period for connection will reduce the benefits of this model for renewable generators. Therefore, a longer time period may need to be complemented by the introduction of more flexible methods of releasing access close to real time, either through the allocation of non-firm and/or short-term firm productions or through the facilitation of trading.

There has been a suite of recent CUSC modifications (CAP 152-155[30]) on the information to be provided as part of the application process. The proposed milestones discussed in these modifications include:

- planning application submitted;
- planning consent awarded;
- power station procurement;
- construction started; and

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30 CAP 152 – Exhibit B Revisions. CAP 153 – Exhibit D Revisions. CAP 154 – Exhibit F Revisions. CAP155 – Exhibit I Revisions.

- construction completed.

In both Full Connect and Manage options, rights are defined with reference to a particular geographical node. At present, nodal rights are priced on a zonal basis. Therefore, as part of the implementation process, it may be appropriate to consider the advantages and drawbacks of moving to nodal pricing for nodal rights.

Both Full Connect and Manage options may result in increased difficulties in system operation compared with present situation, as Final Physical Notifications[31] (FPNs) given by users at Gate Closure[32] are likely to be less compatible with system capabilities. Therefore, the appropriateness of revised system operation arrangements may need to be considered alongside the implementation of revised access arrangements in line with the Full Connect and Manage model.

There are a number of further implementation/development issues that relate to variant 1b of the Full Connect and Manage model. These include:

- assessing the possible volume and cost of constraint actions in Balancing Mechanism or longer timescales. This needs to consider the potential impact on system operation more generally including effects (if any) on system stability and the system operation actions required to manage these effects.
- given the requirement that addition connections must facilitate increased renewable output, then the System Operator would need to consider the expected generation profile (including load factor) of prospective and existing renewable generators. This would require modelling to assess whether a new connection will increase renewable output. This will be contentious, and may prove particularly difficult with respect to emerging technologies.
- treatment of existing rights in respect to repowered or replaced non-renewable plant at the same node. This is determined by the extent to which an incumbent’s access rights are defined with reference to a particular node rather than to physical plant in place at that node.

31 The Final Physical Notification defines the planned generation or consumption of each Balancing Mechanism Unit.

32 Gate Closure is the time after which it is no longer possible to trade, either bilaterally or in exchanges for a particular period. Gate Closure currently occurs one hour before the start of the particular period.

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3. LIMITED CONNECT AND MANAGE

3.1 Introduction

This section relates to the 'Limited Connect and Manage' straw man.

3.1.1 Principles underpinning Limited Connect and Manage model

The main principle underlying the Limited Connect and Manage model is that additional transmission access and the associated connections should be facilitated as far as may be accommodated by the operation of the transmission system in real time, through the issuing of 'non-firm' access rights. The role of the planning standards in determining the timing of new connections would be abolished, but the planning standards would continue to govern the extent to which fully firm access rights are made available. Additional connections and non-firm transmission access would be granted irrespective of whether deep reinforcement had been completed.

The nature of the 'non-firm' rights is such that holders would have the right to submit nominations of their intended generator output at Gate Closure, along with Balancing Mechanism bid prices. These bid prices would allow the System Operator to curtail their output at neutral prices (for example, prices related to the UKPX or APX[33] within-day prices). The price for these non-firm rights will be no more than the price of firm access rights, which would be based on the existing long-run-incremental charging regime. It is anticipated that there may be some trading of firm for non-firm rights, facilitated by the System Operator.

The design of this model is explicitly targeted at drivers B and C above, and to a lesser extent driver A,[34] because it seeks to curtail the costs associated with constraint compensation payable to generators, while ensuring that additional generation would be accommodated to the maximum extent possible on each day, and to a lesser extent driver A (with the distribution of non-firm rights).

3.2 Description of the straw man

Figure 3 provides an outline of the design features associated with the Limited Connect and Manage model. This model is an extension of the collective option C1a that we identified in our previous work (see Annex A for an overview of our previous work). The straw man builds on the existing access arrangements by facilitating the release of long-term non-firm rights at a price less than or equal to the price charged for long-term firm rights.

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33 APX currently operates Spot Markets, reporting prices and volumes traded, as well as notification services for bilateral contracts.

34 See section 1.2.1 above for an explanation of the four model drivers:
- A: Ensure rights to generate are distributed efficiently at the time of delivery
- B: Facilitate release of increased quantity of access rights
- C: Mitigate constraint costs
- D: All generators should face the short-term value of transmission capacity at the margin.

Figure 3 – Limited Connect and Manage straw man

Definition of rights

Common assumptions for all models

- Entry-exit system
- Entry rights only, demand treated implicitly
- Capacity kept separate from energy market

Model features

- Nodal rights (D1a)
- Asymmetric, indefinite rights (D2a)
- Long-term, fully financially firm rights (D3a)
- Additional long-term non-firm rights (D3b)

Allocation of rights

Common assumptions for all models

- Aggregate quantity of firm rights will not be lower than at present

Model features

- Firm rights delivered based on system capability (A1a)
- Additional non-firm rights delivered based on eligible requirements
- Prioritisation of incumbents (A2a)

Pricing of rights

Common assumptions for all models

- LRMC remains the primary source of revenue for the TO

Model features

- LRMC pricing for firm rights (P1a)
- LRMC MINUS pricing for additional non-firm rights

Trading of rights

Common assumptions for all models

- Some form of trading will be possible at least in line with current trading
- Trading of rights within the same geographically defined area can be done at an exchange rate of 1:1

Model features

- Trading of SO defined products (T1a)
- Trading before Gate Closure (T2a)
- SO provides exchange rate on application (T3a)

Source: Pöyry Energy Consulting

3.2.1 *Definition of rights*

The definition of firm rights under the Limited Connect and Manage model is the same as under the Full Connect and Manage model. Therefore, firm access rights are indefinite in nature and defined with reference to a particular geographic node. The obligations upon the System Operator and the holder are asymmetric in nature, as at present, with the holder having relatively ‘short’ commitments while the System Operator has ‘long’ commitments.

Financially firm access rights require the holder to pay for the right, as mentioned above. It also means that the System Operator must provide market based financial compensation payments (e.g. through Balancing Mechanism bid payments) to the holder in the event that a generator's requirement for physical access cannot be accommodated in delivery timescales.

In addition to long-term firm rights, the Limited Connect and Manage model also includes provision for the allocation of additional non-firm rights. These additional rights are non-firm in that there are pre-agreed prices[35] for any buy-back (in the Balancing Mechanism) of rights which cannot be honoured[36]. The standing reserve arrangements include examples of pre-agreed prices.

3.2.2 Allocation of rights

Under this model, priority in the allocation of firm rights is given to existing holders of firm rights. With this in mind, any additional firm access rights are only allocated up to limits imposed by the overall system capability in accordance with planning standards as appropriate. In addition, incremental non-firm access rights in excess of the (planned) system capability are allocated to match eligible requirements, subject to planning standards as relevant.

3.2.3 Pricing of rights

The price of the long-term firm access rights within this model is determined ex-ante based upon a long-run marginal cost-based (LRMC) methodology, as at present. The price of the firm rights will act as a ceiling on the price of the non-firm rights. The extent (if at all) to which the non-firm rights are cheaper than firm rights will be a matter for further consideration at the implementation stage – this could potentially be a trigger for exchange of firm for non-firm rights by existing holders.

3.2.4 Trading of rights

Secondary trading of access rights is not a key feature of this model. However, limited trading opportunities are available, in line with the existing arrangements, and trading of firm for non-firm rights may be accommodated.

For the purpose of trading, access rights can be disaggregated to the level permitted by the System Operator. All trading must occur before Gate Closure. The exchange rate for trading (between the different nodes at which access is conferred) is specified by the System Operator upon application.

3.3 Viability/internal consistency of the straw man

This model focuses on using non-firm rights to provide flexible access to facilitate output from renewable generation. Therefore, the model does not also include other design features which were identified in the previous Pöyry work as increasing the flexibility of access rights. This is because the inclusion of these features in this model and variant may lead to increased cost and complexity without creating any additional benefit in terms of increased firm rights for renewable generators. Such design features include more extensive (re)distribution of firm rights close to real time or secondary trading

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35 Possibly referenced to APX prices to mitigate the risks of distortions to cash-out prices.

36 Quantity based models of non-firm access (e.g. where a user buys an interruptible right) have not been considered explicitly; we consider that the effect is similar to the version that we have considered; in that the holder is entitled to use the access unless there is a binding constraint in which case there is curtailment (at the System Operator's discretion), without (full) compensation.

arrangements. Taking our previous work in relation to transmission access building blocks as a starting point, this section discusses the key interactions between the design features chosen at each decision point.

3.3.1 Indefinite, asymmetric nodal rights and existing trading arrangements

The introduction of non-firm products is designed to provide flexibility that might otherwise be provided by trading of firm access rights. Therefore, this model does not seek to facilitate increased trading of firm access rights. This is compatible with the retention of access rights that are defined indefinitely at a nodal level, which may hinder trading either across or between the portfolio of connected parties. For example, the pre-publication of exchange rates is made more complex by a system of nodally defined rights as there are a much larger combinations of potential trades.

3.3.2 Nodal rights and indefinite duration of firm access rights

Nodal rights do not need to be redefined over time to reflect prevailing generation and demand patterns, as is potentially the case for zonal rights. Nodal rights can, therefore, be defined on an indefinite basis.

3.3.3 Definition of rights, LRMC-based pricing and prioritisation of incumbents

The retention of rights that are broadly consistent in terms of geographical scope, pricing, duration and symmetry with existing rights means that there are no transition issues with respect to prioritising incumbents as the high-level nature of the right that they hold is unchanged.

3.4 Main issues for implementation/development

There are a number of issues that would be associated with the implementation / development of detailed access arrangements based upon the Limited Connect and Manage model.

3.4.1 Non-firm rights as bankable assets that can used to obtain project finance

The extent to which non-firm rights may be not be regarded as bankable assets that can used to obtain project finance may be mitigated by the possibility that incumbents are willing to trade firm rights for non-firm rights, subject to System Operator involvement.

3.4.2 Basis for determining price of non-firm products

The existence of indefinite firm rights alongside incumbent prioritisation makes firm products relatively more attractive than non-firm rights. This means that a greater discount on the price of non-firm rights will be required to encourage incumbents to swap existing firm rights for non-firm rights. However, the arrangements must be designed such that the rights are complementary, avoiding the possibility of one undermining the other.

3.4.3 Geographical definition of pricing

In this model, rights are defined with reference to a particular geographical node. At present, nodal rights are priced on a zonal basis. Therefore, as part of the implementation process, it may be appropriate to consider the advantages and drawbacks of moving to nodal pricing for nodal rights.

3.4.4 Treatment of existing rights when plant is repowered or replaced

There is a need to ensure that the rules relating to the treatment of existing rights in respect to repowered or replaced non-renewable plant at the same node are clear. This is determined by the extent to which an incumbent's access rights are defined with reference to a particular node rather than to physical plant in place at that node.

3.4.5 Interaction with the Balancing Mechanism

The design of the non-firm product should ensure that there is appropriate separation between the pre-agreed BM bids from cash-out pricing.

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4. MARKET BASED ACCESS ALLOCATION AND TRADING

4.1 Introduction

This section relates to the 'Market Based Access Allocation and Trading' straw man.

4.1.1 Principles underpinning 'Market Based Access Allocation and Trading' model

The 'Market Based Access Allocation and Trading' model is intended to facilitate trading of the existing allocated transmission capacity, while including flexibility in both the total quantity of firm rights allocated and the ability of generators to overrun their firm access rights. This is explicitly targeted at drivers A, B and C and to a lesser extent D above[37]; increasing rights through incremental capacity auctions, short-term capacity release and overrun, and enhancing the ability for users to trade the allocations close to real time through the definition of the product and the existence of ex post trading.

The intent is to put all generators on an equal footing when seeking to acquire access rights and to enable the users who have the highest value for access to obtain it, in both long and short timescales. The model seeks to mitigate potential issues associated with the removal/alteration of existing rights identified in Pöyry's building block assessment by adopting a transitional approach to the new arrangements.

The allocation of long-term firm rights would be based on the existing process using planning standards to determine available capacity, supplemented by a mechanism which allows users to offer to pay higher transmission charges in return for National Grid making out-of-the-ordinary attempts to accommodate additional/early access. The allocation of incremental firm rights to users in addition to existing system capability would be based on their willingness to pay. The model incorporates a transition phase during which prioritisation of incumbents is maintained, but this is not an enduring feature of the model.

The quantity of rights available can be increased dynamically closer to real time through the allocation of short-term firm access rights. The quantity of short-term rights made available would be determined based upon the prevailing operational view of capacity availability. Short-term rights would be charged based on the expected short-run costs of access provision. The flexibility of access availability is further enhanced by enabling parties to overrun their capacity right holdings. Overrun would be charged based on the actual short-run costs of providing access in operational timescales.

In addition to more dynamic and flexible access allocation, this model incorporates secondary trading of access rights between users. This provides opportunities for redistribution of rights through trade based on users' requirements for access rights, which may change over time (e.g. wind generators may seek to purchase access rights close to real time when they have greater certainty as to wind conditions, any generator may seek to sell access rights in the event of an unplanned outage etc.).

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37 See section 1.2.1 above for an explanation of the four model drivers:
- A: Ensure rights to generate are distributed efficiently at the time of delivery
- B: Facilitate release of increased quantity of access rights
- C: Mitigate constraint costs
- D: All generators face the short-term value of transmission capacity at the margin.

Trade should theoretically provide a route for those with the highest valuations to acquire access rights and for those with lower valuations to realise the market value by selling their rights at the prevailing price. Effective secondary trading means that the prevailing value of access (in terms of the cost of acquiring rights or the opportunity cost of holding rights) is always an important consideration for users. Therefore, in theory, users should have an incentive to trade access rights where there are commercially attractive opportunities to do so. A liquid secondary trading market should deliver efficient distribution of allocated rights.

4.2 Description of the straw man

Figure 4 provides an outline of the design features associated with the Market Based Access Allocation and Trading model. This model is, following the transition to enduring arrangements, broadly consistent with the connect-and-pay model (C1c) described in our previous work assessing the building blocks of potential models for transmission access arrangements (see Annex A for an overview of our previous work).

Figure 4 – Market Based Access Allocation and Trading straw man

Definition of rights

Common assumptions for all models

- Entry-exit system
- Entry rights only, demand treated implicitly
- Capacity kept separate from energy market

Model features

- Zonal rights (D1b)
- Post-transition: defined period, symmetric (D2b)
  - Pre-transition: asymmetric, indefinite rights (D2a)
- Long-term, fully financially firm rights (D3a)
- Short-term, fully financially firm rights (D3a)
- Overrun allowed (D3c)

Allocation of rights

Common assumptions for all models

- Aggregate quantity of firm rights will not be lower than at present

Model features

- Firm rights delivered based on system capability (A1a+)
- Post-transition: no prioritisation of incumbents (A2b)
  - Pre-transition: Prioritisation of incumbents (A2a)

Pricing of rights

Common assumptions for all models

- LRMC remains the primary source of revenue for the TO

Model features

- LRMC pricing for existing long-term firm rights (P1a)
- LRMC PLUS pricing for incremental long-term firm rights (P1c)
- Ex-ante SRMC for short-term firm rights (P1b)
- Ex-post SRMC for overrun (P1b)

Trading of rights

Common assumptions for all models

- Some form of trading will be possible at least in line with current trading
- Trading of rights within the same geographically defined area can be done at an exchange rate of 1:1

Model features

- Trading of user-disaggregated products (T1b)
- Trading allowed ex-post (T2b)
- Pre-published exchange rate (T3b)

Source: Pöyry Energy Consulting

4.2.1 *Definition of rights*

Under this model, access rights are defined zonally. In terms of duration and obligations attached to firm rights, a distinction is initially drawn between rights covering existing system capacity and rights for incremental system capacity. Our expectation under this model is that this distinction will be removed in the future and that symmetric, fixed duration rights will ultimately replace the existing asymmetric, indefinite rights. The model should, therefore, be evaluated subsequent to the transition to symmetric, fixed duration rights, whilst recognising the possibility of a gradual shift. Clearly, the speed of transition will be an important factor in the development and assessment of this model. These issues are discussed further in section 4.4.

Ultimately under this model, long-term firm rights have a defined duration with a fixed end-point and there is symmetry between the obligations linked to the holder and the System Operator. The holder has 'long' commitments in that it is obliged to pay for the rights over the defined period, with a relatively long notice period[38]. The System Operator's commitment is long as it has to honour an access right holder's long-term rights.

As mentioned above, it is envisaged that all firm rights will ultimately be symmetric and apply for a defined period under this model. However, during the transition from the existing arrangements, firm rights relating to existing system capacity are indefinite in nature and have asymmetric commitments. The transition to fixed duration symmetric rights could be delivered by applying a 'sunset clause' to the existing rights, from which point defined symmetric rights will apply. There are clearly options in terms of the length of time before the sunset clause comes into force, with associated impacts upon the speed of change and the delivery of the benefits that this model may deliver. There are also issues associated with the conversion of asymmetric rights to fixed duration, symmetric rights. These issues are considered further in section 4.4

This model makes explicit provision for long-term and short-term firm rights to be allocated. It is envisaged that short-term firm rights are made available in the period in the run-up to real time following the release of long-term rights (year-ahead, month-ahead, week-ahead, day-ahead etc).

In addition, this model allows generators to exceed their access right holdings (or to run without any access right holdings). Therefore, the option to overrun (and pay the associated price, as discussed below) provides a form of non-firm access under this model.

4.2.2 Allocation of rights

Under this model, existing users' rights are prioritised until the sunset clause is activated.[39] Firm access rights are then allocated in line with overall system capability (noting that the release of short-term firm rights close to real time may enable a greater aggregate level of firm access rights to be allocated, depending upon prevailing system conditions, than is possible under the present arrangements). Incremental firm access rights can also be released if parties are prepared to pay the price associated with the necessary system enhancement, as discussed under the pricing issues below.

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38 In principle, for symmetric rights, the notice period would match the commitment period, leaving the user to trade any rights that are bought but not required. In practice the System Operator may offer some type of buy-back scheme, but with no presumption of a full refund for unused rights which could not be used by others. The design of a buy-back mechanism is outside the scope of this document.

39 It may be the case that some level of compensation is paid to existing right holders given the intended revocation of these rights.

4.2.3 Pricing of rights

The price of long-term firm access rights within this model is determined ex-ante based upon a LRMC methodology, as at present. Incremental long-term access rights would be priced on a willingness-to-pay (LRMC+) basis. LRMC+ prices could be determined with reference to a supply curve indicating the incremental investment costs associated with the provision of additional transmission access. One issue for consideration is whether there should be differentiation in the pricing of access such that incremental capacity is priced at LRMC+ while existing capacity is priced at LRMC, or whether all capacity should be priced consistently at LRMC+. These pricing mechanics are important implementation / development issues. The important point is that incremental access can be secured if users are willing to pay cover all or a specific portion of the incremental investment cost. The current arrangements for the release of incremental gas entry capacity in Great Britain contain an example of such a mechanism. If gas shippers require entry capacity above that available at an entry point on to the transmission system, they must signal their requirement for ‘incremental’ capacity through the Quarterly System Entry Capacity (QSEC) auctions. The release of the incremental capacity is linked to a test of whether the revenue from the auction is greater than half of the net present value (NPV) of the associated projected costs[40].

Short-term firm rights are priced based on the ex-ante short-run marginal cost (SRMC) of provided the associated access, subject to appropriate arrangements for payment for local connection assets and for adequate contribution to the overall network revenue requirement.

Overrun is priced on the basis of ex-post SRMC (i.e. the actual cost associated with managing the system to accommodate the overrun). The (zonal) overrun price could be derived systematically as follows:

- an unconstrained (national) energy price **E** is calculated based on an ex-post unconstrained model using Balancing Mechanism offers and bids (as in BSC Modification Proposal P211 (“Imbalance Price based on Ex-post Unconstrained Schedule”));
- a constrained (zonal) ‘energy’ price **Z** is calculated based on an ex-post constrained model using Balancing Mechanism offers and bids (similar to BSC Modification Proposal P211), but including thermal constraints in a (zonal) representation of the GB network); and
- the transmission price (expressed in £/MWh) is calculated (in each zone) as the difference between the constrained (zonal) ‘energy’ price and the unconstrained (national) energy price (**Z**-**E**).

The right to overrun and/or to acquire short-term capacity could be associated with a per-kW payment for local transmission assets and/or a contribution towards the ‘residual’ element of TNUoS revenue, perhaps based on their Connection Entry Capacity.

4.2.4 Trading of rights

Secondary trading of access rights plays an important role in this model. As a result, there is much greater flexibility in the suggested arrangements for access trading than at present and under the preceding models.

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40 Reference "The Incremental Entry Capacity Release Methodology Statement"; National Grid, 12 June 2007, v7.0

Parties are allowed to sub-divide their access rights temporally into smaller periods (e.g. daily or half-hourly), and trading (or notifications) can occur ex-post. There is a 1:1 exchange rate for intra-zonal right trading and such trades can be conducted without reference to the System Operator. The exchange rate for inter-zone trading is pre-published. All these measures aim to increase the flexibility of the arrangements and to facilitate trade of access rights between parties, in order that the short-run marginal cost is viewed as a cost (or an opportunity cost) by all generators so that efficient decisions are made by generators in relation to their use or trading of transmission access rights in real time.

4.3 Viability/internal consistency of the straw man

As described above, the Market Based Access Allocation and Trading model focuses on market based allocation of rights supported by liquid secondary trading. Taking our previous work in relation to transmission access building blocks as a starting point, this section describes how the different parts of the model interact to achieve this goal.

4.3.1 Zonal rights and trading

As explained above, the model is based on liquid secondary trading. Therefore, the model contains the building block options that in combination facilitate trading. These are a zonal definition of access rights in combination with the ability to trade (ex ante and ex post) between zones using pre-published exchange rates.

4.3.2 Zonal rights and defined period

Where zonally-defined rights are valid for a defined period, the expiration of the rights may provide opportunities for the revision of zonal boundaries (if required) to reflect changes to the geographical pattern of generation and consumption. This avoids the need to change the nature of ‘live’ access rights when zonal boundaries need to change. Therefore, a zonal definition of rights is complemented by a move to defined duration, symmetric rights from existing indefinite, asymmetric rights rights under this model.

4.3.3 Zonal rights and non-prioritisation of incumbents

In order to avoid strengthening an incumbent's position by turning their nodal right into a more flexible and valuable zonal right, prioritisation of incumbents should be avoided. Maintaining prioritisation implies the operation of a two-tier system with additional complexity both in terms of operation and trading. Again, this is a reason to push for transition from existing indefinite, asymmetric rights to defined duration, symmetric rights under this model.

4.3.4 Trading and right definition/allocation

Trading is complemented by reduced/no prioritisation of existing rights and/or some limitation on the duration or asymmetry of access rights.

4.3.5 Trading and short-term access rights

The impact/usefulness of short-term firm access rights and overrun is enhanced if there are arrangements which encourage liquid trading and/or reallocation of long-term rights close to real time.

4.4 Main issues for implementation/development

There remain some implementation/development issues that would need to be addressed during the development of more detailed arrangements based on the high-level model described in this section. These are set out below.

4.4.1 Duration of the sunset clause

At the end of the relevant sunset period, the incumbents will no longer have priority access to their current rights. Effectively, their rights would be removed and their access to rights would be on the same basis as new generators of the same class. Therefore, the length of time before the sunset clause is invoked on the existing access holdings will be central to the assessment and implementation of this model. The sunset clause could be set to activate after, say, 2 years, 10 years or 30 years depending upon the implementation strategy adopted[41]. This decision will affect the assessment of the benefits of the model. For example, a long period before sunset clause activation may mitigate the potential effects of disrupting the rights of existing users but the benefits of the secondary trading of rights may be deferred (and vice versa). This decision will determine the speed of transition.

Developing commercial incentives for existing users to voluntarily switch to fixed duration, symmetric rights in advance of the sunset clause may speed up/ease this transition; for example limiting the extent to which the existing TEC products could be traded, e.g. by retaining their nodal nature.[42]

A two-tier system whereby existing rights are asymmetric and indefinite in duration but newly issued rights are symmetric and of definite duration will need to be supported and administered during the transition process.

4.4.2 Migrating from nodal to zonal rights

As part of the transition, nodal rights need to be migrated into zonal rights. The size and basis for the derivation of the zones is clearly an important issue. We consider that the System Operator should define the zones on the basis of observed and projected power transfers across critical boundaries. The zones contained in the Seven Year Statement (the 'SYS Study Zones') are considered to represent an appropriate starting point for zonal definition. Ultimately this is a compromise between accuracy (and the extent of constraint payments or under-allocation of rights post-trading[43]) and liquidity of the traded product.

The conversion of a nodal into a zonal right provides possible windfall benefits to existing users because, given that they are not linked to a specific location, they allow greater flexibility of rights across a user's portfolio and are more saleable in the secondary market. Emphasising this may provide an additional commercial incentive for existing users to voluntarily switch.

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41 Alternatively, a rolling sunset clause could be introduced which maintains the existing arrangements for a defined period of time from the point of each new connection. This would, however, prolong the operation of a two-tier access rights system.

42 Some form of compensation for the revocation of existing rights could also be considered.

43 An exchange rate which is too generous will increase constraint costs. An exchange rate which is insufficiently generous will reduce the effective quantity of access rights allocated.

Anecdotal evidence from other markets has been presented[44] which suggests that zonal transmission access rights are more open to gaming than nodal access rights, if the generation market (in a particular location) is not competitive.

4.4.3 Long-term and short-term prices

LRMC will act as a floor to the price of long-term firm access rights. Therefore, these rights will be priced at LRMC in unconstrained zones. Where there is scarcity of access rights, the charges for those rights will be at a market-determined price above LRMC. If users are allowed to fix the price that they pay for long-term firm access rights, consideration will need to be given to the impact on the recovery of the residual element is currently included in TNUoS charges.

Given that short-run transmission charging is available as an alternative to the long term product, there needs to be recognition that each generator still requires the maintenance of local (transmission) assets. Some payment might be required to avoid cross-subsidisation; it may be appropriate to consider a per-kW charge for Connection Entry Capacity (CEC) to cover local transmission assets (as distinct from connection-related assets or the more distant parts of the network) in return for the right to overrun and/or acquire short-term firm capacity.

It may be the case in unconstrained zones that the cost of short-term transmission access will be less than the long-term cost. As a result, users in these zones may, to some extent, have a commercial incentive to secure short-term rights or overrun instead of long-term rights, and it may be considered appropriate that all users who retain a right to buy short-term access rights or overrun should contribute to the allowed network revenue. This could be addressed by using Connection Entry Capacity as the basis for some of the existing TNUoS charges (e.g. to cover the Residual element of the existing TNUoS revenue). This may also be complemented by a review by the existing 27%/73% generation/demand split for transmission network revenue.

Given that within-year revenue from short-term sales and the costs and revenue associated with overrun would be less certain, greater reliance would be placed on the year-on-year correction mechanisms for total allowed revenue.

The short-term pricing arrangements for import-constrained zones needs further consideration, although in principle negative prices for short-run products or overrun could be permitted, as for TNUoS.

The pricing of overrun and the resultant cashflow would need to be defined in detail. We note the issue that marginal cost pricing would lead to over-recovery against the costs of provision of the relevant balancing services, and that this net revenue stream could contribute to the 'Residual' element network revenue recovery or be returned to network users (or customers).

4.4.4 Short term allocations and trading

Despite the existence of overrun, the model relies on short-term capacity release and of secondary trading of rights close to real time to ensure that access rights are in the 'correct' hands at the time of generation commitment. The arrangements must be

[44] Reference: presentations made by Shmuel Oren and by Benjamin Hobbs at the 'International Workshop on Transmission Access, Investment and Pricing', hosted by SEDG on 23 October 2007. See www.sedg.ac.uk

designed to maximise the ability of (small) renewable generators to operate effectively in this environment, and to ensure that holders of long term rights are not outside the market for transmission access close to real time; and the costs and likely extent of liquidity of secondary trading must be considered carefully.

At present, there is no incentive on the System Operator to release additional firm capacity close to real time, as any associated revenue is counted as part of the (fixed) allowable revenue, whereas any increased constraint or loss costs are treated as a debit item under the existing System Operator Incentive scheme; these incentives need to be addressed as part of the detailed design.

4.4.5 Locational BSUoS charging (for overrun)

The cost associated with systems changes for generators arising from a move to locational BSUoS charging for overrun and the knock-on implications for BSUoS charging methodology/arrangements will need to be considered in the overall impact assessment and cost-benefit calculations.

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5. LOCATIONAL TRANSMISSION CHARGING WITH TRADABLE FINANCIAL RIGHTS

5.1 Introduction

5.1.1 Principles underpinning 'Locational Transmission Charging with Tradable Financial Rights' model

This section relates to the 'Locational Transmission Charging with Tradable Financial Rights' straw man. The design of this model seeks to ensure that additional generation would be accommodated to the maximum extent possible on each day, while limiting any associated increase in costs of constraint compensation payable to generators. The intention is that all participants face the short run costs of transmission access in each half hour[45] in order to deliver efficient energy trading and (self)-dispatch decisions, while recognising the potential limitations to bilateral trading of transmission access capacity close to real time. This model is therefore targeted at drivers B, C and D and to a lesser extent A above[46].

The role of the planning standards in determining the timing of new connections would be abolished, and additional connections and non-firm (overrun) transmission access would be granted irrespective of whether deep reinforcement had been completed.

All users would therefore hold non-firm (overrun) physical rights[47] for up to their Connection Entry Capacity (CEC), and would thereby be entitled to submit Final Physical Notifications and to generate. After delivery, all generators (including those holding financial access rights) would face locational transmission charges for their actual output based on short-run marginal cost (overrun) principles, ensuring that they would each face the marginal cost of transmission access in delivery timescales. This may be characterised as an overrun-type charge for **all** generation.

The existing TEC product would be replaced by a system of purely financial products, Financial Transmission Entry Capacity (FTEC). Charging for FTEC could be based on the existing long-run-incremental charging regime, and its allocation could be (in the first instance) made to existing holders of TEC.

Holders of the financial capacity rights (FTEC) would receive a payment equating to the short-run marginal transmission price for the relevant zone in each half hour, for the quantity of their access holding (not their actual generation). Secondary trading of FTEC (as a financial product) would be entirely in the hands of the parties concerned and need not (always) involve the System Operator.

45 With the intention of achieving the outcome of an efficient secondary trading market close to real time, without the associated transaction costs.

46 Driver A is included to the extent that all users hold rights to generate at gate closure (as in the Full Connect and Manage models), but that the transmission pricing (if it works in a theoretically correct manner) provides incentives for users to generate in a way which is consistent with transmission constraints, consistent with the (local) merit order.

47 These rights are non-firm in the sense that the user would not know the cost of the access until after the point of delivery (or, potentially, shortly beforehand).

In summary, the Locational Transmission Charging with Tradable Financial Rights model intends to expose users to the full short-run opportunity costs of transmission usage irrespective of whether or not there is effective secondary trading of financial access rights close to real time. The model seeks to achieve this aim by providing physical access exclusively via overrun arrangements, while offering holders of FTEC the opportunity to hedge their (overrun) transmission charges. Whilst the model contains arrangements for secondary trading of financial rights close to time, such trading plays a less significant role than in model three (‘Market Based Access Allocation and Trading’).

The model seeks to mitigate potential issues associated with the removal/alteration of existing rights identified in Pöyry’s previous building block assessment by adopting a transitional approach to the new arrangements.

5.2 Description of the straw man

Figure 5 provides an outline of the design features associated with the Locational Transmission Charging with Tradable Financial Rights model. This model (following the transition to enduring arrangements) has similarities with the non-firm access model (C1d) described in our previous work to assess the building blocks of potential models for transmission access arrangements (see Annex A for an overview of our previous work).

Figure 5 – Locational Transmission Charging with Tradable Financial Rights straw man

Definition of rights

Common assumptions for all models

- Entry-exit system
- Entry rights only, demand treated implicitly
- Capacity kept separate from energy market

Model features

- Zonal **financial** access rights (D1b)
- Symmetric, defined-period financial rights (FTEC) (D2b)
- 'Overrun' to cover all generation (D3c)

Allocation of rights

Common assumptions for all models

- Aggregate quantity of firm rights will not be lower than at present

Model features

- Firm financial rights delivered based on system capability (A1a)
- Non-firm rights (akin to overrun) delivered based on users' requirements (A1b)
- Post-transition: no prioritisation if incumbents (A2b)
  - Pre-transition: Prioritisation of incumbents (A2a)

Pricing of rights

Common assumptions for all models

- LRMC remains the primary source of revenue for the TO

Model features

- LRMC pricing for long-term firm financial rights (P1a)
- Ex-post SRMC charges (via BSUoS) for **all** generation (P1b))
- Holders of FTEC **receive** ex-post SRMC for their holding of FTEC (P1b)

Trading of rights

Common assumptions for all models

- Some form of trading will be possible at least in line with current trading
- Trading of rights within the same geographically defined area can be done at an exchange rate of 1:1

Model features

- Trading of user-disaggregated products (T1b)
- Trading allowed ex-post (T2b)
- SO determined exchange rate between zones (T3a), if permitted

Source: Pöyry Energy Consulting

5.2.1 Definition of rights

Under this model, rights are separated into firm financial rights and non-firm (overrun) quasi-physical rights.

Existing Transmission Entry Capacity (TEC) rights are superseded by a financial product, Financial Transmission Entry Capacity (FTEC) which confers long-term (financial) access rights on holders.

FTEC would be defined as a zonal product, and would be valid for a defined period and with a symmetric commitment on behalf of the holder (to pay the relevant transmission network charges) and the System Operator (to make the financial payments associated with FTEC holding).

In practice, we anticipate a transition phase, as in the 'Market Based Access Allocation and Trading' model above, during which time existing TEC holders might retain a more limited form of financial access right[48]. The model should, therefore, be evaluated subsequent to the transition to symmetric, fixed duration rights but recognising the possibility of a soft landing.

As with the 'Market Based Access Allocation and Trading' model, the transition to FTEC could be delivered by applying a 'sunset clause' to the existing or interim FTEC rights, from which point full FTEC rights will apply. This presents issues for implementation, which are considered below.

Separately, all users hold rights to generate up to the level of their Connection Entry Capacity (CEC), subject to paying short-run transmission charges, which vary by location by half hour and which are akin to overrun charges applied to all generation. (Additional per-kW charges may be levied on generators' CEC, to cover their local assets and the residual element of the TNUoS revenue).

5.2.2 Allocation of rights

Under this model, existing users' rights are prioritised for an initial period, and existing TEC holders would exchange their allocations for equivalent quantities of the new FTEC access right (or a limited version of it, termed Transitional FTEC). We envisage that the allocations of Transitional FTEC to existing holders would be time-limited, with more limited applicability and that there would a planned migration to the core FTEC product which is of defined duration and with symmetric obligation on behalf of both the holder and the System Operator.[49]

In this simple version of the model, it is assumed that the existing regime for determining the total quantity of FTEC would be retained for the allocation of FTEC, i.e. that the quantity of FTEC is allocated in line with overall system capability in accordance with some planning standard. Ultimately, the allocation of FTEC relates only to financial matters and not to actual generation on the system and the applicability of the GB SQSS to FTEC allocations would need to be reviewed in that light.

As a potential enhancement to the model, it would be possible to offer incremental FTEC capacity in return for willingness-to-pay in excess of the standard transmission network charge. However, in order to retain a distinction between the straw man models, we have elected not to include this aspect of the model in this definition.

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48 For example, in a transitional phase, existing TEC holdings might be migrated to financial rights which relate to a quantity less than the full access holding (intended to ensure that compensation is paid for constraints not for a generator being out of merit); which are limited in terms of secondary trading (e.g. nodal rather than zonal); and which do not require the same level of symmetric user commitment. These rights could expire after a suitable 'sunset' period.

49 It may be the case that some level of compensation is paid to existing right holders given the intended revocation of these rights.

5.2.3 Pricing of rights

Generators face short run locational transmission charges for their entire delivered output, expressed in £/MWh, based on short-run marginal cost (overrun) principles. This translates into a locational (zonal) BSUoS for generation based on actual generation output, calculated as follows (for each half hour independently):

- an unconstrained national energy price **E** is calculated based on an ex-post unconstrained model using Balancing Mechanism offers and bids (as in BSC Modification Proposal P211);
- a constrained zonal 'energy' price **Z** is calculated based on an ex-post constrained model using Balancing Mechanism offers and bids (similar to BSC Modification Proposal P211), but including thermal constraints in a zonal representation of the GB network); and
- the transmission price (expressed in £/MWh) is calculated (in each zone) as the difference between the constrained zonal 'energy' price and the unconstrained (national) energy price (**Z**-**E**).

FTEC acts as a financial hedge for the short-run locational transmission charge. Holders of FTEC are entitled to receive payments from the System Operator, equal to the value of their zonal transmission price, multiplied by the MWh equivalent of their holdings of FTEC[50].

The price of financial firm access rights (FTEC) within this model is determined ex-ante based upon a LRMC methodology, as at present. The price of incremental long-term access rights is based on a higher LRMC which covers the costs associated with enhanced system capability.

The pricing of FTEC relates only to financial matters and not to physical conditions and the applicability of the existing TNUoS regime would need to be reviewed in that light. In particular, the present 27%/73% split of allowed revenue between generation and demand may need review, and it is possible that the residual element of the TNUoS revenue (and potentially some of the cost of local assets) would be recovered through a per-kW charge on Connection Entry Capacity (which would confer the right to access the system in return for payment of a short-run transmission price).

It is possible that generators with the right to generate up to their Connection Entry Capacity would pay some option fee for this right, in addition to the short-term transmission charge for use of the system. For example, this fee could encompass the present 'Residual' element of the TNUoS revenue, and could separately encompass payment for local assets (which are currently included in the regulated asset base and funded through TNUoS). In this case, the charge for FTEC might deviate from the existing TNUoS, since the residual element would be recovered separately.

50 Note that FTEC confers financial compensation for the full quantity of the holding, whereas the existing arrangements are intended to provide compensation only to the extent that a generator is constrained off (e.g. against its submitted level of intended generation, its Final Physical Notification).

5.2.4 Trading of rights

Secondary trading of financial access rights plays a role in this model, but less so than under model three ‘Market Based Access Allocation and Trading’, and there is no presumption of liquid trading of short-duration access products close to real time.

The financial nature of the products traded (FTEC) means that the System Operator need have limited involvement in secondary trades, as settlement may be entirely bilateral. As a consequence, there is great freedom for parties to trade FTEC, including sub-dividing financial access rights temporally into smaller periods (e.g. daily or half-hourly), and ex-post trading. There is no presumption that inter-zonal trades would be facilitated by the System Operator. Ultimately, the System Operator would have to recognise transfers of FTEC rights since they are associated with obligations (e.g. to pay the equivalent of TNUoS).

An important feature of the secondary trading is that it relates to a financial (hedge) product rather than the right to generate in real time. Therefore, achieving capacity holdings to support efficient (self-)dispatch decisions does not rely on effective secondary trading, since **all** generation is exposed to the ‘overrun’ transmission pricing.

5.3 Viability/internal consistency of the straw man

Taking our previous work in relation to transmission access building blocks as a starting point, this section describes the key interactions between the design features chosen at each decision point.

5.3.1 Zonal rights and defined period

The compatibility of zonal and fixed duration rights discussed in the context of the Market Based Access Allocation and Trading model are also relevant here.

5.3.2 Zonal rights and non-prioritisation of incumbents

Zonal rights coupled with non-prioritisation of incumbents (after the transitional period) are appropriate here as it avoids strengthening an incumbent's position by turning their nodal right into a zonal right, which confers greater flexibility and value.

5.3.3 Trading and short-term access rights

This model circumvents the need for liquid trading of short-duration firm access rights close to real time, while retaining the flexibility for generators to access the system and face short-run marginal costs. The financial access product is tradable.

5.4 Main issues for implementation/development

There remain some implementation/development issues that would need to be addressed during the development of more detailed arrangements based on the high-level model described in this section. These include:

5.4.1 Transitional arrangements

A two-tier system of rights will exist during the transition period[51] – we envisage a transition of existing rights to the new FTEC product which may include use of a more limited Transitional FTEC product for existing holders in the interim. This will need careful definition to ensure that FTEC does not provide a greater level of compensation than the existing TEC rights[52].

Issues relating to the duration of the sunset clause and the potential to create commercial incentives for users to voluntarily switch Transitional FTEC to FTEC, discussed in the context of the Market Based Access Allocation and Trading model, are also relevant here.

5.4.2 Long-term and short-term prices

Given that short-run transmission charging is available as an alternative to the long term product, there needs to be recognition that each generator still requires the maintenance of local (transmission) assets. Some payment might be required to avoid cross-subsidisation; it may be appropriate to consider a per-kW charge for Connection Entry Capacity for local assets in return for the right to overrun and/or acquire short-term firm capacity, with a more limited TNUoS revenue recovery.

It may be the case in unconstrained zones that the cost of short-term transmission access will be less than the long-term cost. As a result, users in these zones may, to some extent, have a commercial incentive to secure short-term rights or overrun instead of long-term rights, and it may be considered appropriate that all users who retain a right to buy short-term access rights or overrun should contribute to the allowed network revenue. This could be addressed by using Connection Entry Capacity as the basis for some of the existing TNUoS charges (e.g. to cover the Residual element of the existing TNUoS revenue).

Given that within-year revenue from short-term sales and the costs and revenue associated with overrun would be less certain, greater reliance would be placed on the year-on-year correction mechanisms for total allowed revenue.

The short-term pricing arrangements for import-constrained zones needs further consideration, although in principle negative prices could be permitted. Similarly, the extent to which FTEC should be a one-way product providing compensation for positive (short run) transmission charges, or a two-way product which requires the user to pay if the (short run) transmission charge is negative, needs further consideration.

The pricing of overrun and the resultant cashflow would need to be defined in detail. We note the issue that marginal cost pricing would lead to over-recovery against the costs of provision of the relevant balancing services, and that this net revenue stream could contribute to the 'Residual' element network revenue recovery or be returned to network users (or customers).

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51 This may be addressed through the use of sunset clauses. It is also likely to interact with zonally defined rights where the rights are not linked to a specific location.

52 At present, access rights can be argued to relate to users' chosen level of Final Physical Notification, rather than their entire TEC holding, which in competitive conditions should restrict their access to the level of 'in-merit' generation on a GB-wide basis. FTEC relates to the entire holding rather than to the 'in-merit' generation.

5.4.3 Converting nodal to zonal rights

As part of the transition, nodal rights need to be migrated into zonal rights. The size and basis for the derivation of the zones is clearly an important issue. We consider that the System Operator should define the zones on the basis of observed and projected power transfers across critical boundaries. The zones contained in the Seven Year Statement (the 'SYS Study Zones') are considered to represent an appropriate starting point for zonal definition; ultimately this is a compromise between accuracy (and the extent of constraint payments or under-allocation of rights post-trading) and liquidity of the traded product. In this model which places reduced emphasis on trading, more weight could be given to accuracy than in other models; even a nodal approach would be feasible.

Given the financial nature of the FTEC product, the extent to which the conversion of a nodal into a zonal right provides possible windfall benefits to existing users is less clear than in other models[53].

Anecdotal evidence from other markets has been presented[54] which suggests that zonal transmission access rights are more open to gaming than nodal access rights, if the generation market (in a particular location) is not competitive.

By emphasising the transfer of rights within a zone, there needs to be recognition that each generator still requires the maintenance of local (transmission) assets. Some payment might be required to avoid cross-subsidisation; it may be appropriate to consider a per-kW charge for Connection Entry Capacity for local assets (and potentially a contribution to the Residual TNUoS revenue element) in return for the right to overrun and/or acquire short-term firm capacity, with a more limited TNUoS revenue recovery.

5.4.4 Converting physical to financial rights

The removal of the link to physical access in the rights held by incumbents will need to be considered in terms of potential implications for project financing, existing contracts etc.

Potential windfall gains arising from converting TEC into a product which covers the entire generation capacity rather than (at present) their chosen level of (in-merit) generation will need to be evaluated; this could be mitigated by limiting payments under Transitional FTEC such that it compensates for transmission constraints but not a generator being out-of-merit.

The implementation will need to include a review of the applicability of the GBSQSS and the existing pricing regime for a purely physical product, rather than the existing quasi-physical TEC, and what planning standard (if any) should be used to govern users' rights to overrun.

5.4.5 Locational BSUoS charging

The cost associated with systems changes for generators arising from a move to locational BSUoS charging and the knock-on implications for BSUoS charging

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53 In a model in which the rights are actively traded, zonal rights are likely to be more attractive than nodal rights as they allow greater flexibility of rights across a user's portfolio and are associated with a more vigorous trading process.

54 Reference: presentations made by Shmuel Oren and Benjamin Hobbs at the 'International Workshop on Transmission Access, Investment and Pricing', hosted by SEDG on 23 October 2007. See www.sedg.ac.uk

methodology/arrangements will need to be considered in the overall impact assessment and cost-benefit calculations.

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6. SUMMARY

6.1 Introduction

This section summarises the straw man models identified in this document, the process by which these models were derived, and our findings with regard to implementation issues and specific issues for further assessment.

6.2 Process

Building upon the objective of the TAR to "support the delivery of the government's aspiration of 20% of electricity being supplied by renewable generation", we have developed straw men models in terms of the four drivers below:

- Driver A: Ensure rights to generate are distributed efficiently at the time of delivery;
- Driver B: Facilitate release of increased quantity of access rights;
- Driver C: Mitigate constraint costs; and
- Driver D: All generators face the short-term value of transmission capacity at the margin.

With these drivers in mind, the process for developing straw man models began with the production of a long list of possible options, based on output from a combination of our own previous work on building block options/combinations and the TAR process itself. The long list of possible models was subjected to a review, refinement and selection process, which resulted in agreement between Pöyry, Ofgem and BERR on the four straw man models that would undergo further consideration.

The four selected straw man models (one of which contains a variant) are as follows:

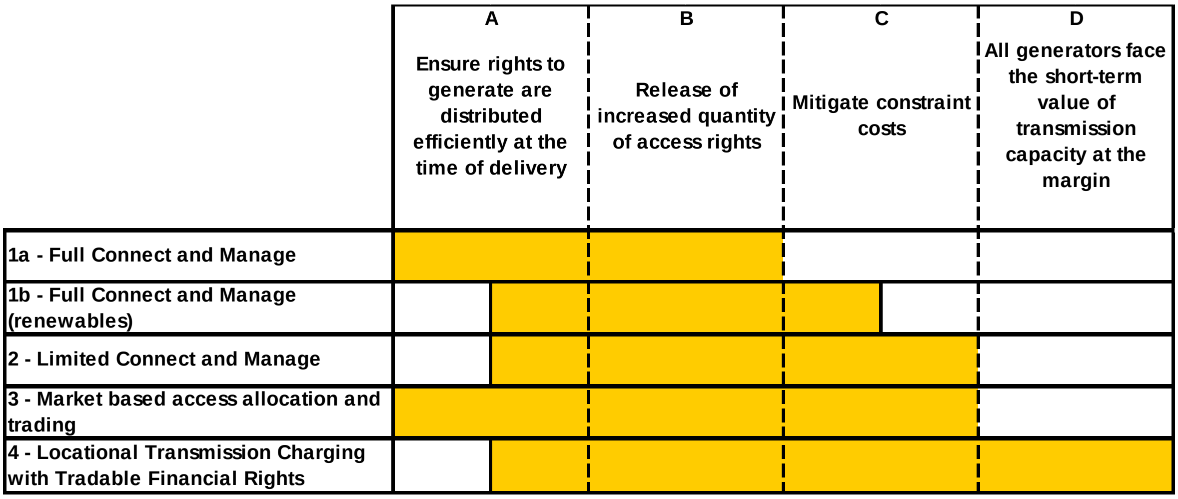
1. Full Connect and Manage (including a variant);
2. Limited Connect and Manage;
3. Market Based Access Allocation and Trading; and
4. Locational Transmission Charging with Tradable Financial Rights.

6.3 Overview of the straw man options

6.3.1 Linkage to drivers

Figure 6 highlights the intended linkages between each of the straw man models and the four drivers listed above, noting that this explains the thinking behind the model definitions and is not intended to be in any way an assessment of the outcomes of the models. As these drivers are to some extent competing aims, each model strikes a different balance between them.

Figure 6 – Intended drivers of the four straw man models



Source: Pöyry Energy Consulting

6.3.2 *Key building blocks of four straw man models*

Figure 7 provides a summary of the building block options which combine to make up the four straw man models that we have identified. This refers to the building block options identified in our previous work, as summarised in Annex A.

Figure 7 – Key building blocks of the four straw man models

	1 – Full Connect and Manage	2 – Limited Connect and Manage	3 – Market based allocation and trading	4 – Locational transmission charging with tradable financial rights
Definition of rights	▪ Nodal rights (D1a) ▪ Asymmetric, indefinite rights (D2a) ▪ Long-term, fully financially firm rights (D3a)	▪ Nodal rights (A1a) ▪ Asymmetric, indefinite rights (A2a) ▪ Long-term, fully financially firm rights (A3a) ▪ Additional long-term non-firm rights (A3b)	▪ Zonal rights (D1b) ▪ Post-transition: defined period, symmetric (D2b) transition: asymmetric, indefinite rights (D2a) ▪ Long-term, fully financially firm rights (D3a) ▪ Short-term, fully financially firm rights (D3a) ▪ Overrun allowed (D3c)	▪ Zonal financial access rights (D1b) ▪ Symmetric, defined-period financial rights (FTEC) (D2b) ▪ 'Overrun' to cover all generation (D3c)
Allocation of rights	▪ Rights delivered based on eligible requirements (A1b) ▪ Incumbents not prioritised (A2b) Variant – 1b ▪ Rights for non-renewables delivered based on system capability (A1a) ▪ Additional rights for renewables delivered based on eligible requirements conditional on impact on renewable deployment (A1b) ▪ Prioritise incumbents (A2a)	▪ Firm rights delivered based on system capability (A1a) ▪ Additional non-firm rights delivered based on eligible requirements ▪ Prioritisation of incumbents (A2a)	▪ Firm rights delivered based on system capability (A1a+) ▪ Post-transition: no prioritisation of incumbents (A2b) transition: Prioritisation of incumbents (A2a)	▪ Firm financial rights delivered based on system capability (A1a) ▪ Non-firm rights (akin to overrun) delivered based on users' requirements (A1b) ▪ Post-transition: no prioritisation if incumbents (A2b) transition: Prioritisation of incumbents (A2a)
Pricing of rights	▪ LRMC-based pricing (P1a)	▪ LRMC pricing for firm rights (P1a) ▪ LRMC MINUS pricing for additional non-firm rights	▪ LRMC pricing for existing long-term firm rights (P1a) ▪ LRMC PLUS pricing for incremental long-term firm rights (P1c) ▪ Ex ante SRMC for short-term firm rights (P1b) ▪ Ex post SRMC for overrun (P1b)	▪ LRMC pricing for long-term firm financial rights (P1a) ▪ Ex post SRMC charges (via BSUoS) for all generation (P1b) ▪ Holders of FTEC receive ex post SRMC for their holding of FTEC (P1b)
Trading of rights	▪ Trading of SO defined products (T1a) ▪ Trading before Gate Closure (T2a) ▪ SO provides exchange rate on application (T3a)	▪ Trading of SO defined products (T1a) ▪ Trading before Gate Closure (T2a) ▪ SO provides exchange rate on application (T3a)	▪ Trading of user disaggregated products (T1b) ▪ Trading allowed ex post (T2b) ▪ Pre-published exchange rate (T3b)	▪ Trading of user disaggregated products (T1b) ▪ Trading allowed ex post (T2b) ▪ SO determined exchange rate between zones (T3a), if permitted

Source: Pöyry Energy Consulting

6.4 Implementation/development issues

For each of the models identified, we have identified issues which need to be considered further as part of the ongoing development/implementation of any of the straw man models. These high-level issues are summarised in Table 1.

Table 1 – Potential implementation/development issues

Full Connect and Manage (model and variant unless otherwise stated)	**Limited Connect and Manage**	**Market Based Access Allocation and Trading**	**Locational Transmission Charging with Tradable Financial Rights**
Changes to core industry documents			
Revisions to SO balancing arrangements and SO incentives			
Eligibility conditions and timescales for firm right allocation	Basis for determining price for non-firm products	Transition arrangements, including duration of sunset clause, commercial incentives and/or compensation for existing right holders	
Constraint management, system operation issues	Non-firm rights as bankable assets	Migrating from nodal to zonal rights	
(1b) extent to which additional renewable generation can be accommodated without reducing renewable output	Implications of possibility of nodal pricing for nodal rights	Relationship between long-term and short-term prices	
(1b) focus on expected or connected generation and associated modelling	Treatment of repowered or replaced non-renewable plant	Locational short-term pricing, BSUoS	
(1b) treatment of repowered or replaced non-renewable plant	Interaction with the Balancing Mechanism	Arrangements for short term allocations and trading	Converting physical to financial rights

Source: Pöyry Energy Consulting

These issues need to be considered during any assessment of the straw man models.

ANNEX A – TAR BUILDING BLOCKS

A.1 Building block options

The development of viable straw man models within this document builds upon work already undertaken by Pöyry for BERR/Ofgem as part of the TAR to identify and qualitatively assess individual transmission access building blocks[55]. The straw man models described in this document follow the building block structure identified in that work, which was, in turn based upon the 'key generic features' of transmission access models identified by Ofgem at the seminar on 5 November 2007. The building block structure and options

The building block levels of any transmission access solution were identified as being:

- the definition of access rights (D);
- the allocation of access rights (A);
- pricing of access rights (P); and
- provisions for secondary trading of access rights (T).

Each building block consists of one or more decision points, for each of which there are several options. The decision points and options available at each are summarised in Table 2 to Table 5. These decision point options and Identification Codes (ID codes) are referred to within the main body of this document.

55 Reference: 'TAR Building Blocks & Options', version 3_0, Pöyry Energy Consulting, 18 December 2007

Table 2 – Definition: list of decision points and options

Decision point	Option ID code	Option description
Geographic definition	D1a	Nodal
	D1b	Zonal
Durability and obligations (long term products)	D2a	Indefinite, asymmetric
	D2b	Defined period, symmetric
Firmness of access products	D3a	Fully firm when commitment is made to purchase
	D3b	Interruptible/non-firm access right with level of firmness or price revealed ex-ante
	D3c	Non-firm right that allows generator to access the system (perhaps within specified limits) with ex-post pricing

Table 3 – Allocation: list of decision points and options

Decision point	Option ID code	Option description
Total allocated quantity	A1a	'System-driven' limits
	A1b	'Requirements-driven' limits
Treatment of existing rights	A2a	Prioritise incumbents (in respect of existing rights holdings)
	A2b	No prioritisation of incumbents

Table 4 – Pricing: list of decision points and options

Decision point	Option ID code	Option description
Basis for pricing	P1a	LRMC (basis)
	P1b	Cost-based willingness-to-pay SRMC (basis)
	P1c	Bid-based willingness-to-pay (e.g. LRMC+)

Table 5 – Secondary trading: list of decision points and options

Decision point	Option ID code	Option description
Temporal divisibility	T1a	In line with SO defined products (presently 28 day minimum)
	T1b	Further subdivision e.g. daily or half-hourly
Last time for bilateral trading	T2a	Before or at gate closure
	T2b	Defined ex-post
Trading between zones (or nodes)	T3a	Based on exchange rate provided on application
	T3b	Based on pre-published exchange rate

Source: Pöyry Energy Consulting

A.2 Collective options

During our qualitative assessment of the individual building block options, we identified 'collective' options based on combinations of mutually reinforcing individual options, gathered together to form possible sub-components of an end-to-end solution. The collective options identified are listed below:

- C1a 'status quo' - firm rights (D3a) allocated within system-driven limits (A1a), with prioritisation of incumbents (A2a) and priced on a LRMC basis (P1a);
- C1b 'connect-and-manage' - firm rights (D3a) allocated beyond system-driven limits (A1b), with prioritisation of incumbents (A2a) and priced on a LRMC basis principles (P1a);
- C1c 'connect-and-pay' - firm rights (D3a) allocated up to a quantity somewhere between system-driven limits (A1a) and 'requirements driven (A1b), with no prioritisation of incumbents (A2b) and priced on a willingness-to-pay (LRMC+) basis (P1c); and
- C1d 'non-firm access' - combining the status quo with a suite of interruptible/overrun products (options D3b or D3c) for which either the permitted quantities or the access prices (option P1b, using SRMC principles) are set close to real time.

These collective options and the associated ID codes are referred to within the main body of this document.

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ANNEX B – SHORTLISTING OF CANDIDATE MODELS

B.1 Introduction

This Annex sets out a set of seven candidate straw man models. These candidate models were discussed with Ofgem/BERR on 23 January and four were selected for further definition.

The intent behind the definition of the seven candidate models and the four straw man models was to combine the following:

- to use as a starting point for discussion the options included within the TAR Call for Evidence[56] and the second TAR stakeholder workshop held on 5 November 2007;
- to ensure that, for each of the main decision 'building blocks' identified in the previous Pöyry work[57], the range of valid options was covered; and
- based on the previous Pöyry work, to capture the links between building blocks and the 'collective' options (variants of the price, quantity and firmness of access rights allocated to users) which we found to be mutually reinforcing.

These seven candidate models were then subjected to a review, refinement and selection process to ensure that there was no unnecessary duplication, and the four straw man models were agreed for further consideration.

It should be noted that the candidate models presented in this Annex were at a very early stage of design and the four straw man models in the main document are further developed.

B.2 Candidate Straw Man High Level Summary

The 'framing assumptions' made as part of our previous building block assessment work also apply to the candidate straw man models identified below. Seven 'candidate straw man' models are outlined in below and are described in brief in the sections that follow.

We have concluded that an objective of revised arrangements should be to ensure that, on the day, total rights are not less than the actual system capability. This could be delivered by close-to-real-time release of short-term products and/or by the use of non-firm products (e.g. overrun); but the existing TEC allocation rules (which are contingency-dependent), however freely TEC is re-traded after initial allocation, appear **not** to facilitate the full use of network capacity at all times.

The models set out below consider only one type of non-firm access product (other than overrun). We adopt an option for 'non-firm' products in which there are administered prices for any buy-back (in the Balancing Mechanism). Quantity-based models or non-

56 Reference 'Transmission Access Review - A Call for Evidence for a Review of Transmission Access'; ibid.

57 Reference: 'TAR Building Blocks & Options', ibid.

firm access (e.g. where a user buys an interruptible right) have not been considered explicitly; we consider that the effect is similar to the version that we have considered (whereas overrun is another type of non-firm access right).

Table 6 – Definition of candidate models (long list for further refinement)

			Candidate Straw man model						
Building block level	**Decision point**	**ID**	**Full C&M**	**Full C&M for Renewables Only**	**Limited C&M**	**Evolution with Overrun**	**Evolution with Overrun and Flexible Trading**[58]	**Market Driven Allocation**	**Locational transmission charging, tradable financial rights**
Definition	Geographic	D1	a (Nodal)	a (Nodal)	A (Nodal)	a (Nodal)	b (Zonal)	b (Zonal)	b (Zonal)
	Durability and obligations	D2	**All**: a (Indefinite, asymmetric)	**All**: a (Indefinite, asymmetric)	**All**: a (Indefinite, asymmetric)	**Existing**: a (Indefinite, asymmetric) **Incremental**: b (Defined period, symmetric)	**Existing**: a (Indefinite, asymmetric) **Incremental**: b (Defined period, symmetric)	**All**: b (Defined period, symmetric)	**Existing**: a (Indefinite, asymmetric) **New**: b (Defined period, symmetric)
	Firmness	D3	**Long-term right**: a (Fully firm when commitment is made to purchase)	**Long-term right**: a (Fully firm when commitment is made to purchase)	**Long-term right**: a (Fully firm when commitment is made to purchase) AND **Long-term right**: b (Interruptible/non-firm access right with level of firmness or price revealed ex-ante)	**Long-term right**: a (Fully firm when commitment is made to purchase) AND **Overrun**: c (right that allows generator to access the system with ex-post pricing)	**Long-term and short-term rights**: a (Fully firm when commitment is made to purchase) AND **Overrun**: c (right that allows generator to access the system with ex-post pricing)	**Long-term and short-term rights**: a (Fully firm when commitment is made to purchase) AND **Overrun**: c (right that allows generator to access the system with ex-post pricing)	**Long-term (financial) products**: a (Fully firm when commitment is made to purchase) AND **Short-term (physical) products**: c (right that allows generator to access the system with ex-post transmission pricing)

58 This model has been renamed to form the 'Market Based Allocation and Trading' model.

			Candidate Straw man model						
Building block level	**Decision point**	**ID**	**Full C&M**	**Full C&M for Renewables Only**	**Limited C&M**	**Evolution with Overrun**	**Evolution with Overrun and Flexible Trading**[58]	**Market Driven Allocation**	**Locational transmission charging, tradable financial rights**
Allocation	Total allocated quantity[59]	A1	**Firm**: b ('Requirements-driven' limits)	**Firm for non-renewable users**: a ('System-driven' limits) AND **Firm for renewables only**: b ('Requirements-driven' limits)[60]	**Firm**: a ('System-driven' limits) AND **Non-firm**: b ('Requirements-driven' limits)	**Firm**: a+ ('System-driven' limits PLUS)[61]	**Firm**: a+ ('System-driven' limits PLUS)	**Firm**: a+ ('System-driven' limits PLUS)	**Firm (financial)**: a ('System-driven' limits) **Non-firm (physical)**: b ('Requirements-driven' limits)
	Treatment of existing rights	A2	b (No prioritisation of incumbents)	a (Prioritise incumbents)	A (Prioritise incumbents)	a (Prioritise incumbents)	a (Prioritise incumbents)	b (No prioritisation of incumbents)	a (Prioritise incumbents)

59 An objective should be to ensure that, on the day, total rights available equal, as closely as possible, the actual system capability. Options which include short-term products provide an opportunity for additional rights to be allocated close to real time based (presumably) on a more accurate view of the likely system capability on a given day. Overrun also provides an option for helping to ensure that the full system capability is made available.

60 A ceiling/limit may be applied such that additional firm access rights are only allocated when the new renewable projects are not likely to displace existing renewable projects.

61 'System-driven' limits PLUS means that the system capability can be increased over and above its current limit in cases where users' willingness to pay an increased LRMC-based charge for incremental capacity covers the associated investment (or operational) cost associated with granting additional access.

			Candidate Straw man model						
Building block level	**Decision point**	**ID**	**Full C&M**	**Full C&M for Renewables Only**	**Limited C&M**	**Evolution with Overrun**	**Evolution with Overrun and Flexible Trading**[58]	**Market Driven Allocation**	**Locational transmission charging, tradable financial rights**
Pricing	Basis	P1	**Long-term firm right**: a (LRMC basis)	**Long-term firm right**: a (LRMC basis)	**Long-term firm right**: a (LRMC) AND **Long-term non-firm right**: a- (LRMC MINUS)	**Long-term firm right for existing**: a (LRMC) AND **Long-term firm right for incremental**: c (LRMC PLUS) AND **Overrun**: b (ex-post SRMC)	**Long-term firm right for existing**: a (LRMC) AND **Long-term firm right for incremental**: c (LRMC PLUS) AND **Short-term firm right**: b (ex-ante SRMC) AND **Overrun**: b (ex-post SRMC)	**Long-term firm right**: a (LRMC) AND **Short-term firm right**: b (ex-ante SRMC) AND **Overrun**: b (ex-post SRMC)	**Long-term firm product for existing users**: a (LRMC) **Long-term firm product for new users**: c (LRMC PLUS) **All physical delivery**: b (SRMC)
Trading	Temporal divisibility	T1	a (In line with SO defined products)	a (In line with SO defined products)	A (In line with SO defined products)	a (In line with SO defined products)	b (Further subdivision e.g. daily or half-hourly)	b (Further subdivision e.g. daily or half-hourly)	b (Further subdivision e.g. daily or half-hourly)
	Last time for bilateral trading	T2	a (Before or at Gate Closure)	a (Before or at Gate Closure)	A (Before or at Gate Closure)	a (Before or at Gate Closure)	b (Defined ex-post)	b (Defined ex-post)	b (Defined ex-post)
	Trading between areas	T3	a (Exchange rate provided on application)	a (Exchange rate provided on application)	A (Exchange rate provided on application)	a (Exchange rate provided on application)	b (Based on pre-published exchange rate)	b (Based on pre-published exchange rate)	a (Exchange rate provided on application) [ex-ante only]

Source: Pöyry Energy Consulting

B.3 Full Connect and Manage

B.3.1 *Key features:*

- There is no system-based restriction on access allocations and all parties are allocated their full requirement of firm (indefinite, asymmetric) rights.
- This effectively preserves incumbent users' rights, although there is no explicit prioritisation.
- The price of firm rights is determined on the basis of a long-run marginal cost (LRMC) methodology, such as the TNUoS regime.

B.3.2 *Consequences:*

- The System Operator will have to take constraint actions in the event that rights cannot be fulfilled, with the costs feeding in Balancing System Use of System (BSUoS) charges.

B.4 Full Connect and Manage for Renewables Only

B.4.1 *Key features:*

- Incumbents' existing (indefinite, asymmetric) access rights are prioritised.
- Renewable generators can obtain firm (indefinite, asymmetric) access rights equal to their overall requirements (subject to a potential restriction limiting the provision of additional access rights which are likely to simply displace existing renewable generators).
- The price of firm rights is determined on the basis of a LRMC methodology, such as the TNUoS regime.

B.4.2 *Consequences:*

- Excluding new conventional generation from Full Connect and Manage arrangements may reduce the potential constraint costs.
  - such arrangements would discriminate against new conventional generation.

B.5 Limited Connect and Manage

B.5.1 *Key features:*

- Incumbents' existing (indefinite, asymmetric) access rights are prioritised.
- Firm (indefinite, asymmetric) rights are allocated up until the capability of the system, with non-firm rights allocated above this level to meet aggregate requirements.
- If non-firm access cannot be provided in operational timescales, it is envisaged that the System Operator will constrain the relevant generator(s) off through the Balancing Mechanism at predetermined bid prices[62].

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62 In this model, access is non-firm in terms of price in the sense that the System Operator will constrain down/off a generator based on the associated price. It is assumed that the pre-determined bid prices associated with non-firm access in this model will be such that constraining off those with non-firm access first would be economic for the System Operator.

- The price of firm rights is determined on the basis of a LRMC methodology.
- The price of these non-firm rights is a discounted LRMC price.

B.5.2 Consequences:

- The cost of constraint actions is likely to be mitigated relative to 'Full Connect and Manage' because non-firm access will, where feasible, be constrained off first at the predetermined bid price
- Arrangements discriminate between existing and new users, to the extent that new users have rights that exceed the capacity of the system.

B.6 Evolution with Overrun

B.6.1 Key features:

- Incumbents retain their existing (indefinite, asymmetric) rights, which are priced on a LRMC basis (as at present)
- Some new definite, symmetric rights are issued (in excess of existing system capability) when parties are willing to pay a price determined by a price schedule that reflects the LRMC associated with the incremental investment (LRMC PLUS)[63].
- As not all users have long-term firm rights equal to their requirements, overrun is allowed.
- Overrun charges are determined by out-turn (i.e. ex post) SRMC.

B.6.2 Consequences:

- New generators are treated less favourably than existing generators.
- Exposure to constraint costs is limited.
- Parties without long-term firm access rights are able to access the system through overrun at ex-post SRMC.

B.7 Evolution with Overrun and Flexible Trading[64]

B.7.1 Key features:

- Rights are defined on a zonal basis to facilitate secondary trading.
- Incumbents retain their existing (indefinite, asymmetric) rights (which will be transferred into zonal rights), which are priced on a LRMC basis (as at present).
- Some new definite, symmetric rights are issued (in excess of existing system capability) when parties are willing to pay a price determined by a price schedule that reflects the LRMC associated with the incremental investment (LRMC PLUS).

Quantity based non-firm access, where x interruptions in period y are allowed are not envisaged (although such an approach is possible).

63 It is envisaged that an evolutionary approach will involve a transition towards fixed duration, symmetric rights.

64 This model has been renamed to form the 'Market Based Allocation and Trading' model.

- As not all users have long-term firm rights equal to their requirements, flexibility is provided by the availability of short-term firm rights, the allowance of overrun and the encouragement of secondary trading (including ex-post).
- Short-term rights are priced at ex-ante SRMC.
- Overrun charges are determined by out-turn (i.e. ex post) SRMC.
- Trading is encouraged, particularly in the short-term.

B.7.2 *Consequences:*

- New generators are treated less favourably than existing generators.
- Exposure to constraint costs is limited.
- Parties without long-term firm access rights are able to access the system through overrun, short-term rights and the use of flexible secondary trading mechanisms.

B.8 Market Driven Allocation

B.8.1 *Key features:*

- Rights are defined on a zonal basis to facilitate trade.
- Incumbents lose priority access to their existing rights.
- Symmetric, definite access rights are issued up to the point when parties are willing to pay a price determined by a price schedule that reflects the LRMC associated with the incremental investment (LRMC PLUS).
- As not all users have long-term firm rights equal to their requirements, flexibility is provided by the availability of short-term firm rights, the allowance of overrun and the encouragement of secondary trading.
- Short-term rights are priced at ex-ante SRMC.
- Overrun charges are determined by out-turn (i.e. ex post) SRMC.
- Trading is encouraged, particularly in the short-term.

B.8.2 *Consequences:*

- There is limited exposure of the System Operator to constraint costs.
- All parties are treated equally.
- Incumbents likely to experience in a reduction in their holding of long-term firm access rights.

B.9 Locational Transmission Charges and Financial TEC

B.9.1 *Key features:*

- all participants face locational transmission charges, expressed in £/MWh, based on short-run marginal cost (overrun) principles; this translates into a locational (zonal) BSUoS for generation based on actual generation output, calculated for each half hour independently.
- TEC is superseded by a financial product (“FTEC”), denominated in MW and linked to a specific zone, which acts as a hedge for the locational transmission charge.

  - holders of FTEC are entitled to receive payments from the System Operator, equal to the value of their zonal transmission price, multiplied by the MWh equivalent of their holdings of FTEC.

- In the allocation of FTEC, incumbents retain priority access to their existing (asymmetric, indefinite) rights, whereas new connectees obtain rights which are symmetric in terms of obligations on the user and on National Grid, and for a defined time period [there may be a sunset clause on the indefinite holdings].
- FTEC is issued within existing (system-determined) limits, and its charging basis is based on long-term principles (e.g. TNUoS).
- Incremental FTEC is offered by the System Operator based on willingness-to-pay which covers the associated cost of increased holdings. This means that fewer rights are issued than are demanded based on existing LRMC-based prices.
- No long-term non-firm rights are formally issued, but since overrun is permitted any party implicitly holds non-firm rights. [As an alternative, the rights to overrun could be sold at some equivalent to the existing residual element of TNUoS].
- Since not all users have long-term firm rights equal to their requirements, overrun is allowed by any user (limited by CEC) [or by the party having paid the residual charge].
- Trading of FTEC is encouraged, particularly in the short-term, including ex-post before settlement of the transmission charges. Inter-zonal access rights can be traded ex-post in [HH blocks] on the basis of pre-published exchange rates.

B.9.2 Consequences:

- All parties are exposed to the locational charge at the margin.
- Holders of TEC retain a commercial equivalent to their existing rights.
- There is limited exposure of the System Operator to constraint costs (which are incurred through payments for the FTEC product), net of receipts of the locational transmission charge and of TNUoS.
- Trading of FTEC is facilitated in several ways – the product is zonal, trading may take place in an ex-post window (so that users can trade based on their actual output rather than a forecast).

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