FINAL REPORT

R01071

PHYSICAL AND FINANCIAL CAPACITY RIGHTS FOR CROSS-BORDER TRADE

Prepared for:

Directorate-General Energy
European Commission

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EXECUTIVE SUMMARY

Booz & Company in association with Professor David Newbery (University of Cambridge) and Professor Goran Strbac (Imperial College, London) present this draft final report on "Physical and financial capacity rights for cross-border trade in electricity (from regional markets to a single European energy market)".[1] We were asked to study the market institutions for long-term electricity transmission rights and to address the following main objectives:

- To identify the advantages and disadvantages of long-term transmission rights being tradable in a secondary market (discussed in chapter 2 of the report);
- On the assumption that it is desirable that secondary trading should take place in long-term transmission rights, should these rights be financial transmission rights (FTRs) or physical transmission rights (PTRs), including variant possibilities, such as both types being available, or hybrid rights (discussed in chapter 3 and 4 of the report); and
- On the assumption that it is desirable that secondary trading should take place in long-term transmission rights, put forward a set of practical recommendations, including the preconditions necessary, for a facilitating a market in the rights which will meet the needs of participants, and deliver efficient and reliable long-term price signals (discussed in chapters 4 and 5).

We previously presented an interim report that concentrated on the first two objectives. In this draft final report, we attempt to finalise conclusions, and address the third point. This is a draft report, and we have not reached full and clear conclusions on all matters.

We are instructed to take the Target Electricity Model (the "Target Model") as the relevant description of the Single (European) Electricity Market within which we are to examine the desirability of the tradability of long-term transmission rights. There are three key parts to the Target Model:

- In relation to the day-ahead market for capacity management and allocation, the Target Model favours a market coupling approach, linking mainly energy-only power exchanges, and modelled on Nord Pool.
- The Target Model requires TSOs to sell forward capacity, but leaves open whether this should be in the form of physical transmission rights (PTRs) or financial transmission rights (FTRs). A movement to FTRs would represent a change in the present situation in Europe where most transmission trading is done on the basis of PTRs.
- The Target Model notes as highly desirable that there should be a secondary market in transmission rights, but does not require it.

The report first evaluates a number of possible objectives and draws conclusions about the extent to which these objectives can usefully guide their design and that of the markets on

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1 *Procured by the European Commission Directorate-General Energy as tender ENER/B2/453/2010 under framework contract TREN/R1/350-2008 Lot 2.*

which they would be traded. The report argues that the appropriate key objectives for a trading system in cross-border transmission capacity are the following:

- Promotes efficiency in the use of cross-border transmission infrastructure;
- Promotes competition between generators across borders;
- Tends to mitigate market power in generation, rather than reinforce it;
- Facilitates required investment in cross-border transmission capacity;
- Allocates risk to TSOs that it is efficient for them to bear, and rewards them appropriately for bearing that risk; and
- Accommodates intermittent generation.

The following are not key objectives in themselves, but rather are indicators that the above are being achieved:

- Meets the needs of generators and load customers who wish to enter into long-term supply contracts;
- Ensure that rights required to be tradable are defined so that the markets for them are transparent and likely to be liquid; and
- Facilitates the effective use of low-carbon generation capacity.

Finally, although not a key policy objective in itself, the following characteristic will reduce political resistance to the implementation of the policy:

- Avoids negative impacts on stakeholders.

The report discusses the risk-offsetting benefits and price-discovery aspects of contracting in unbundled liberalised electricity markets, and notes that transmission rights facilitate cross-border trade, thus granting access to larger market areas, which improves competition, reduces costs, and helps buffer intermittent wind power. Physical contracts have the attraction that they can be bilaterally agreed to suit the contracting parties, but as both generators and consumers need to rebalance their portfolios closer to delivery time as they acquire more accurate information about their circumstances, so they need to be able to trade these contracts on secondary markets. Trading requires standardisation, at some cost in that the contracts are no longer perfectly adapted to mutual requirements, but that cost is reduced if the prompt and spot markets are transparent and liquid. Standardised physical contracts in most commodity markets evolve into financial contracts that have lower transaction costs and are more readily cleared through clearing houses that eliminate counter-party risk. The preferred contract within price zones that have liquid spot markets is a financial Contract for Difference.

At present cross-border trading requires a Physical Transmission Right (PTR), and where day-ahead markets are coupled, these typically take the form of options that can either be nominated day-ahead or, if not, are sold by the Market Operator and the revenues given to the rights holder. As such a forward physical contract from a generator in one country to a load across the border together with a PTR is equivalent to a contract for difference (CfD) and a one-sided FTR (one-sided in that the holder is entitled to any positive value but not liable for the cross-border price difference when this is negative), provided markets on each side are liquid. Two-sided FTRs in which the holder is liable if the price difference is negative have the very considerable advantage that they can be netted, so that the absolute value of the total volume of contracts from one country into its neighbour can greatly exceed the cross-border capacity, considerably enhancing competition in each market.

In this report we analyse all the potential options for developing an appropriate TRs market within the Target Model context. These are Physical Transmission Rights, Financial Transmission Rights (Options and Obligations) and Flowgate Rights. Throughout this report we have assumed that the Single European Electricity Market will operate under the principles of zonal flow-based market coupling (FBMC). As such we have identified a number of limitations of the zonal approach.

Bearing in mind these limitations we tentatively present our key conclusions:

- Long-term contracts including transmission rights are desirable, as they reduce risk and help to underwrite the investment plans of large industrial consumers. These consumers need the assurance well ahead of time that they can meet demand at acceptable prices, and are not forced to rely on volatile and potentially expensive day-ahead markets for more than a small fraction of their demand. In addition, long-term contracts can facilitate entry by new generators, who value the ability to sell their output forward for longer periods, and may be reluctant to rely on short-term markets where they compete with large, well-established and often vertically integrated incumbents.
- FTRs appear to have several advantages over the present system of PTRs for trading over interconnectors and no obvious disadvantages, even when PTRs are combined with the minimal requirements to mitigate market power described below. Their main advantage is that a standard two-sided FTR is automatically a firm obligation and as such can be netted to release a potentially far larger market on either side of any interconnector. In addition, PTR physical nomination ahead of market coupling has the potential to lead to inefficient market dispatch, adverse flows and reduced Available Transfer Capacity (ATC) for the day-ahead market coupling. By design, FTRs are not nominated and are only settled financially independent of the market dispatch, which implies that all the computed day-ahead Net Transfer Capacity (NTC) will be available for the market coupling.[2]
- As a general rule, financial contracts have lower transaction costs than physical contracts and can more readily be transacted through clearing houses that reduce counter-party risk. Part of that derives from the requirement that they need to be standardised to be liquid, and standardised PTRs would share similar advantages, although arguably to a lesser extent.
- FTRs can facilitate zone-to-zone trading without the requirement to explicitly specify the interconnectors that may be involved. On the other hand, PTRs are defined as rights for trade over a specific interconnector. There is therefore a fundamental advantage of FTRs over PTRs in a multi zone system, as the trading parties would need to specify only source / generation zone and sink / load zone, but not all multiple interconnectors that link these zones (and there would a potentially large number of possible "contract path" routs between the two zones in which trading

[2] *NTC is Total Transfer Capacity less the Transmission Reliability Margin that takes account of technical uncertainties on future network conditions, while ATC is NTC less already allocated capacity.*

parties are located). In this context, we recommend that the Target Model should facilitate long-term auctions of zone-to-zone FTRs.

- It is often argued that a working system with FTRs would require cross-border trading to be conducted through the power exchanges (PXs), similarly to the mandatory nodal gross-pools. It is recognised that any type of compulsory PX would not be in line with the philosophy of the bilateral models that dominate EU electricity market designs. There is an additional concern that compulsory PX arrangements would increase the costs of cross-border trading. This could be easily overcome by allowing market participants to inform TSOs of their intentions and nominate self-dispatch trades (to the TSOs) including volume, injection and withdrawal points. After day-ahead FBMC is cleared, self-dispatched market participants would pay a cross-border access charge equal to the zonal price difference between their injection and withdrawal points. Market participants would be able to hedge this access charge through purchases of FTRs. The self-dispatched trades would be included in the market-coupling algorithm as must-accept bid and offers and the rest of the market would be cleared. In this way, PX participation would not be compulsory and no extra costs would be incurred for facilitating long term cross-border bilateral trading. PXs would continue to facilitate voluntary trading of the residual market, as is the case at present.

- As appears to have been widely appreciated and accepted, granting the holders of PTRs the right to withhold capacity confers market power and allows the price difference across the interconnector to be higher than would otherwise be the case. In general that is undesirable, although it can be defended in certain cases as an appropriate way of charging for an interconnector, in the presence of the financial constraints that may exist for example for a stand-alone merchant interconnector. If that is considered the best practical way of enhancing interconnection, the fact that it confers some market power (as do patents) requires derogations under existing EC regulations. Such withholding can be readily prevented under the existing practice of use-it-or-lose/sell-it (UIOLI or UIOSI). But this arrangement provides a narrower opportunity for trading, and will not deliver the level of market integration FTRs can provide.

- As also appears widely accepted by regulators, generators located in importing zones may have the ability to exercise increased market power if they secure a large fraction of PTRs. But if the transmission rights are traded in liquid and transparent markets, and if traders are good at arbitraging the coupled markets, incumbent generators in the import region will be unable to secure these PTRs and to exercise this potential additional market power, since they will be outbid by traders. The reason is simple – the incumbent will only earn the domestic marginal revenue from using the PTRs, while the traders will receive the full local market price, and that will necessarily exceed the marginal revenue if there is any market power to be exercised. Some regulators (e.g. in the Netherlands) restrict purchases of transmission rights by domestic generators, and this should allay market power concerns, and more directly, should create more liquidity in the transmission rights markets, which is a necessary condition for effective arbitrage and hence the ability to outbid generators.

- Our recommendation is that the TSOs issue FTR Obligations and, if technically and economically feasible, additionally Options. The FTRs should be auctioned in periodic auctions subject to the Simultaneous Feasibility Test and NTC calculations on the full common grid model. Auctions will be single price auctions, so that all rights of the same type sold in one auction are sold at the same price. Furthermore, we have been unable to find any reasons why TSO issued FTR Obligations and Options should not be complemented by financial derivatives, such as CfDs, if such markets evolve organically. Due to the important advantages of netting, the absolute priority should be towards issuing FTR Obligations. FTR Obligations also present the advantage that they can be chained to create rights connecting non-adjacent Zones. This decomposition property should increase trading opportunities and increase liquidity. If it is not too technically challenging (as has been the case in some US markets), and probably later, TSOs should aim to issue FTR Options, to give market users the widest range of choice. Algorithms exist to evaluate simultaneous auctions of Obligations and Options, but are complex.

- Our recommendation is that the duration of transmission rights should match the preferred tenor of energy contracts, which is likely to cover multiple year time horizons, say at least three years ahead. This would require calculating NTC values well in ahead of real time, which might be problematic. NTC calculation methodology involves making assumptions on the state of the transmission grid and calculating Reference Flows,[3] which depend on market conditions and wind in-feeds. This implies that the longer the duration of the TRs the more conservative the NTC values for the auction will be. Nonetheless, as has been the case in PJM, there is potential for a significant amount of transmission rights to be auctioned with multiple years duration even with zero NTC. This, however, is only possible with FTR obligations due to netting. Later auctions can issue more rights as assumptions clarify.
- Secondary and OTC markets for TRs are important for the efficient operation of the TR market so as to increase liquidity and enhance price discovery. Market participants that wish to trade FTRs between similar zones or hubs would be able to trade bilaterally their transmission rights. Zonal market designs should be significantly more liquid than Nodal (we note that for node-to-node FTRs secondary trading and re-configuration of TRs requires a centrally administered auction process). Nevertheless, it is our recommendation that periodic reconfiguration[4] auctions are held, if necessary, perhaps quarterly and monthly, as this should enhance the trades across interconnectors.
- We stress that is important that Flow-Based Market Coupling should be based on a detailed network model in order to accurately represent the underlying physical reality of the network as otherwise this may lead to an inefficient dispatch, which is highly undesirable.

  But even if the network is accurately presented this will not resolve an inherent problem with the Target Model and FBMC approach, which is that the amount of

[3]For an explanation of Reference Flows see 3.4.5

[4] In the US, often 100% of capacity is released at the earliest date. Reconfiguration auctions are auctions at which the TSO adjusts to the capacity now known to be available, which might often be a buy back of capacity it now no longer has available, eg for reason of outage or maintenance. For the EC, we are recommending that ATC is sold, which is typically less than 100% of physical capacity. So typically as time proceeds ATC will rise as certainty improves. But it might occasionally happen that ATC reduces because of planned maintenance, or other known outage. So in the EC reconfiguration auctions might be more frequently releases of additional capacity, although buy-backs of withdrawn capacity may also occur.

capacity available for trade across interconnectors, in a meshed network, will be **market condition dependent**, that is, it depends on the pattern of injections which will change according to electricity and fuel prices, and other market factors. The dependency of interconnector capacity on market condition is less problematic for the day ahead market, but it is typically very significant for longer-term transmission rights. This is because market conditions can be predicted with a reasonably high degree of certainty day ahead (although increasing amounts of intermittent generation capacity reduce the level of certainty to some degree), but predicting market conditions with high degree of certainty over the longer term is fundamentally problematic.

The capacity offered will not only depend on the availability of the transmission system but will be driven by various aspects of market operation including, generation forced and maintenance outage patterns and durations, fuel prices and merit order dispatches, changes in wind generation outputs[5] and changes in demand.[6] Any discrepancy between forecasted and actual realisations in any of these factors will lead to revenue inadequacy (over or under recovery of revenue associated with FTR). The key concern is that this inherent problem with the market design may undermine the overall objective of the enhancing long term cross-border trades as a key element of the development of the EU single electricity market. Careful consideration of alternative options for handing of revenue adequacy and TSO incentive scheme will be a key to mitigating efficiently the effects of this market design problem.

We would point out that these problems are mostly resolved in nodal/LMP based market designs, although no market design can entirely remove the risk of the exercise of market power. In effect, in nodal/LMP systems, subjected to the Simultaneous Feasibility Test, all the physical transmission capacity can be auctioned. It can be shown that the ISOs will be always revenue adequate irrespective of the actual realisation of the market condition and actual plant dispatch at any point in time,[7] provided that the network physical capacity sold is delivered. In contrast, according to the Target Model design, TSOs could be revenue inadequate even if all network assets are made available.

- As the market conditions drive the amount of capacity over interconnectors that may be available, there are clearly several issues that need resolving:

  - Determining / agreeing on the market condition assumptions that should be used to quantify the amount of interconnector capacity that can be made available to the network users in the long term;
  - Defining the boundaries and hence sizes of Zones; and
  - Incentive regime for TSOs associated with the delivery of cross-border capacity.

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[5] *We stress that resolving priority access driven network access inconsistencies for wind generation, which highly desirable (discussed in section 2.6), will not however eliminate the problem of the dependency of interconnector capacity on the level of generation from wind farms*

[6] *This may be particularly relevant given the increase in distributed generation of various forms that will change the demand seen by the transmission system and the possibility of schedulable load (e.g. electric vehicles) enabled by smart meters.*

[7] *That is, irrespective of whether wind blows or not, irrespective of any changes that may have occurred in gas / coal prices that may have fundamentally change generation dispatch, irrespective of which plant is on maintenance and for how long.*

Regarding the first two issues, these are empirical question and would need to be analysed on a case-by-case basis in order to ensure the robustness of decisions associated with the volume of the cross-border capacity that is made available for long term auctions, so that changes in market condition do not affect significantly the Reference Flow (that is, the spatial pattern of injections and load used to estimate ATC).

Regarding incentive regimes, we stress that if TSOs are required to take commercial risks associated with cross-border capacities that will be delivered far ahead in future, given the Target Model and the proposed NTC calculation methodology, this may lead to very limited volumes of cross-border capacity being offered in long term auctions. Hence, we suggest that the remuneration regimes for TSOs, which lie within the responsibility of national regulators, should be encouraged to be designed so that they see their interest lying in maintaining network availability, but not in speculating about the future generation maintenance patterns, bidding strategies, wind patterns etc. Clearly, anything that exposes TSOs to substantial risks affected by the choices of market participants, or encourages it to assume risks associated with the position taken, will inevitably lead to it taking conservative views on the available NTC, and potentially undermine the aspirations of the single European electricity market.

For these reasons, the minimum amount of capacity that TSOs release should not be a matter of their commercial discretion, but rather should be set out in rules. Such rules would need frequent refinement, so the rules should live in a suitable institution that can be frequently revisited and updated in the light of experience and developments.

- The zonal market design and NTC calculation methodology may create opportunities for gaming by market participants, i.e., apparently perverse strategic choices by market participants that take advantage of the operation of the rules to make a profit, or disadvantage competitors. In particular, portfolio generators (in importing or exporting zones) could strategically dispatch their assets in order to affect the NTC (either reducing it or increasing it) leading to FTR revenue inadequacy that may be commercially advantageous. This is an area that EU regulators should actively monitor through examining the operating conditions that lead to revenue inadequacies.

- Given the limitations of the market design due to the inevitable NTC calculation, it is impossible rigorously to prescribe a specific percentage of the physical capacity of the interconnectors for auctioning of transmission rights. Since the NTC depends on the assumptions for Reference Flow calculation, the auctioned volume in different timescales should reflect the materiality of these assumptions. We however point out that by auctioning FTR obligations the volume of the auctioned rights can be maximised given the NTC constraints. Similarly, the financial revenue adequacy of the TSOs with respect to the auctioning of TRs should differentiate between released volume from the Reference Flow calculation and the availability of the physical capacity of the grid. In particular, we recommend that TSOs are compensated, through their regulated revenue, the full financial cost due of any potential discrepancies between the assumed Reference Flows and actual flows due to intra-zonal trades. On the other hand, TSOs could be incentivised to maximise the availability of the physical capacity of the grid, above the amount specified, but this would be a matter for national regulators.

- TSOs should be required to issue FTRs at least in amounts such that their arithmetic sums satisfy the security-constrained optimal dispatch, treating FTRs in the opposite direction as having negative values compared to the reference direction. There are likely to be advantages in issuing amounts of varying durations, and either encouraging continuous trading or holding periodic auctions where they can be retraded (the choice to depend on their respective transaction costs, liquidity, depth and market demand). When the quantity of ATC changes, either due to further releases, increase due to increased certainty, or reductions due to known capacity outages, adjustments can be made through auctions (reconfiguration auctions), which may also facilitate users to retrade their rights, as well as in other secondary trading opportunities. TSOs would be liable for compensation equal to the full cross-border price difference in the event of the failure of a link or other event preventing trade in volumes equal to the net quantity of FTRs, and would be allowed to recover any short-fall in their cross-border auction revenues as a first charge on the accumulated revenues from that source and through their regulated revenue.

- It is our recommendation that all rights auctioned by TSOs, with the exception of sub-sea links and merchant links, are 100% financially firm, or, at least, just as firm as the TSOs offer intra-zonal customers. The financial arrangements that apply to TSOs, for example in relation to the use of surpluses congestion rents, or funding deficits, are a matter for national regulators, and matters such as the management of capacity availability and *force majeure* arrangements that TSOs can apply to their customers falls within that. But it is important that the arrangements in relation to interconnection customers, both for firmness and for allocation of congestion costs, do not discriminate in favour of intra-zonal customers. If TSOs discriminate in favour of intra-zonal customers, this is an impediment to market integration and inconsistent with the internal market.

- We bring to the attention of the commission that allocating the costs of revenue adequacy is a complicated topic which should be further analysed and falls within the general topic of inter-TSO compensation. Other topics requiring further study include integrating markets with different designs (though this should not be used as an excuse for delaying integration); the allocation of cross-border reinforcement costs better to recover them from the beneficiaries; zone definition; whether power exchange participation can reasonably be made mandatory for cross-border traders or whether there should be a right to avoid participation; the trade-off between ATC and security standards.

- In the case of sub-sea links the technical characteristics of these assets differ significantly from terrestrial networks. In particular, the repair times may be significantly longer reaching up to several months compared to several days for terrestrial links. Hence offering the same level of firmness for technically different assets might not be appropriate.

- All actions should be taken, including providing sufficiently granular load flow data to the relevant SO, to maximise the value of all interconnectors between different price zones. This will require advance notification to the market operator charged with clearing the integrated cross-border auctions of all planned injections (including those contracted and self-dispatched) and predicted loads at a nodal level where that degree of granularity is necessary to model critical bottleneck flows. As a route to achieving this end, we strongly recommend that the EC require TSOs to maintain past records of generation and load flows at a sufficiently fine temporal and geographical resolution, and provide sufficiently detailed grid diagrams, for analysis by independent experts, who will use the data to establish the extent to which current practice falls short of an optimal dispatch.

- Markets may be expected initially to have low liquidity, which means that price formation will initially be poorer than when liquidity improves. Because of initially low liquidity, it is preferable initially to sell a proportion of ATC at longer dates, and build up to selling the full amount as liquidity rises. Likewise, when price formation is still weak, reconfiguration auctions should be relatively infrequent, and options not sold. As liquidity builds up, reconfiguration auctions can be made more frequent, and options released.

FUTURE WORK

We recommend that the EC should promote futher work on subjects including the following:

- Allocating the costs of revenue adequacy
- Allocation of cross border investment costs
- Integration of markets of different designs
- Mandatory Power Exchange participation
- Zone definition
- ATC under different security standards
- TSO incentives and governance

In general, we believe it is possible to implement the conclusions of this report without coming to a final view on the above issues. These are matters that will improve the integration of the electricity market, and the efficiency of the market in transmission rights. But the fact that they are worthy of further study should not prevent the initiation of a long term market for cross-border transmission rights mediated by FTR Obligations.

1. INTRODUCTION

1.1 BACKGROUND

Booz & Company in association with Professor David Newbery (University of Cambridge) and Professor Goran Štrbac (Imperial College, London) are pleased to present this final report for the study entitled "Physical and financial capacity rights for cross-border trade in electricity (from regional markets to a single European energy market)". This was procured by the European Commission Directorate-General Energy as tender ENER/B2/453/2010 under framework contract TREN/R1/350-2008 Lot 2.

We previously presented our interim report and our draft final report to the Commission. The interim report has also been presented to stakeholders at the Florence Forum and at a workshop in London, where outside experts also contributed. The draft final report was discussed with the Commission, and also circulated by the Commission to a number of stakeholders.

1.2 PURPOSE OF THE STUDY

The terms of reference of the study require that we study the market institutions for long-term electricity transmission rights. In specific terms, Booz & Company understand that the Commission is looking for the study to address the following objectives (which we have paraphrased and collated from the specification for purposes of clarity):

- To identify the advantages and disadvantages of long-term transmission rights being tradable in a secondary market;
- On the assumption that it is desirable that secondary trading should take place in long-term transmission rights, should these rights be financial transmission rights (FTRs) or physical transmission rights (PTRs), including variant possibilities, such as both types being available, or hybrid rights; and
- On the assumption that it is desirable that secondary trading should take place in long-term transmission rights, put forward a set of practical recommendations, including the preconditions necessary, for a facilitating a market in the rights which will meet the needs of participants, and deliver efficient and reliable long-term price signals.

The terms of reference additionally set out eight specific tasks describing detailed issues in relation to transmission rights that should be studied.

1.3 PROGRESS OF THE STUDY

The terms of reference require us to make a number of interviews of stakeholders. We have interviewed all the stakeholders specified, except that ERGEG is winding up, but we have interviewed CEER, closely related to ERGEG, instead. We have also made contact with ERGEG's replacement body ACER, who were content to attend our workshop and draw a number of issues to our attention. We have additionally, on the advice of the Commission, interviewed Europex.

We have given all stakeholders ample opportunity to comment on our interim report, and we have had several meetings during this period, and received some written comments, as well as listening to them. The draft final report has also been circulated by the Commission.

In this report we set out our final conclusions and recommendations.

1.4 STRUCTURE OF THE REPORT

Chapter 2 of this report covers the first objective of the study. We set out the institutional background, and devise a framework for assessment. The purpose of tradable long-term transmission rights, and the way they work is examined. From this, we draw conclusions on desirability.

Chapter 3 presents analysis and a factual basis for the recommendation on the form of transmission rights, and the eight tasks in relation to those rights.

In Chapter 4, we present our main conclusions.

In Chapter 5, we deal with some details of implementation.

In Chapter 6, we make some recommendations for further study. However the implementation of the recommendations of this report can proceed without a final decision on many of the other things that can be studied, they can be improved or harmonised later if appropriate.

2. THE DESIRABILITY OF LONG-TERM TRADING

2.1 INTRODUCTION

This chapter sets out our evaluation of the advantages and disadvantages of tradable long-term rights for cross-border electricity transmission capacity. It is essentially the same as in the interim report, but following discussions of the interim report with stakeholders we believe the arguments are robust.

We first set out the institutional context in which this project sits, both the legislative situation and the administrative processes that will take place to construct the market institutions for a Single European Market in Electricity. On the basis of that, we move on to set out our framework for analysis: what should be the objectives for the Single European Market, against which advantages and disadvantages can be assessed.

The high level architecture of the market institutions for electricity is currently laid out in the Target Electricity Model. The task of designing this model has so far been allocated to a subcommittee of the Florence Forum, a regular meeting of stakeholders of no legal standing but which is respected as representing some kind of consensus. We set out the key features of the Target Model.

We follow this with a discussion of long-term contracting in the electricity market. This is the arena in which long-term tradable rights for electricity will be used. We supplement this with two sections of worked examples to illustrate how the market will operate. The course of this exposition is not only intended to facilitate understanding of the workings of the market, but also to exposes many of the advantages and disadvantages. A section follows on coping on the effect of increasing quantities of wind energy, which is important for managing cross-border flows as its output is hard to predict until a very short time before delivery.

Finally, we summarise our emerging conclusions on advantages and disadvantages, against the framework for analysis we identified. These are provisional as we have not had opportunity to discuss them with stakeholders yet, and there remain questions still to be addressed.

2.2 INSTITUTIONAL CONTEXT

The legislation in the Third Energy Package recognises that efficient markets in electricity and access to electricity transmission require effective regulatory and market institutions for carrying out that trade, as well as some central coordination. Such effective market institutions do not simply emerge naturally in the electricity industry, as they might in competitive commodity markets, merely by creating the correct competitive conditions. Rather, because of the special features of electricity, requiring instantaneous last minute balancing by the system operator, the need to maintain security and quality of service given the laws of physics and the constraints in the transmission system as well as the natural monopolies inherent in the networks, and the need to resolve information asymmetries, an explicit set of Network Codes and related arrangements must be selected, agreed and implemented. Market outcomes will depend upon the precise design of these arrangements. The present Directives do not specify the arrangements, nor the timing of their creation and extension to the whole community, but have set up a system with authority for allowing for migration towards it.

The European Union has recognised that completing the internal market in energy more generally, and electricity more specifically, is essential to achieving its energy objectives. These objectives, and the necessity of completing the internal market, were set out in the Council's document, *An Energy Policy for Europe* (COM(2007)-1). This acknowledged that steps taken towards an internal market in electricity (as at 2007) fell well short of creating a single market: price correlation between regional markets remained poor; transmission capacity connecting regional markets remained inadequate; its use was often inefficient, and there were substantial institutional barriers to customers choosing their electricity supplier or obtaining access on reasonable terms to the transmission facilities.

At about the same time, the EC published the document *Prospects for the Internal Gas and Electricity Market* (COM(2006)-841), which said

> "On the one hand, during this time, the basic concepts of the internal energy market have become embedded in terms of the legal framework, institutional arrangements and the physical infrastructure such as IT equipment. However, at the same time meaningful competition does not exist in many Member States."

It noted many obstacles to competition (para 1.4), (discussed in more detail in *Inquiry pursuant to Article 17 of Regulation (EC) No 1/2003 into the European gas and electricity sectors (Final Report)* (COM(2006)-851)) and identified the following as key outstanding issues.

- "Ensuring non-discriminatory access to networks through unbundling"
- "Improve regulation of network access at national and EU level"
- "Reducing the scope for unfair competition"
- "Co-ordination between transmission system operators"
- "Providing a clear framework for investment in generation plant/gas import and transmission infrastructure"
- "Issues related to households and small commercial customers"

All Member States opened their gas and electricity markets by July 2007, to the timetable and degree required by the legislation, albeit that compliance with a number of detailed requirements measures was incomplete in certain countries. Whilst clearly this was an important step on the route to the creation of an internal market, a progress report from the Commission in 2008 (*Progress in creating the internal gas and electricity market* SEC(2008)-460) indicated that considerable further progress on the objectives listed above was still required. They noted, *inter alia*, that:

> "Restrictions to free and fair competition have, however, developed through the coexistence of open market segments and end-user supply price regulation."
>
> "Market integration has still not developed to a sufficient extent. This is demonstrated by price differences, regional monopolies and persistent cross-border congestion between Member States, for example."
>
> "Despite some encouraging improvements, notably on cross-border coordination at regional level, the overall analysis of progress on the internal market in electricity and natural gas shows that major barriers to the efficient functioning of the market still exist."

In light of this, the EU proceeded towards the Third Energy Package of legislation, which was adopted in 2009, and came into force in March 2011. The Third Package includes in particular, in relation to the internal market in electricity, Directive 2009/72/EC *Concerning common rules for the internal market in electricity*, Regulation 713/2009 *Establishing an Agency for the Cooperation of Energy Regulators,* and Regulation 714/2009 *On conditions for access to the network for cross-border exchanges in electricity*.

Directive 2009/72/EC provides for unbundling of transmission, non-discrimination among system users, and transparency of system use. In particular, it requires that each country has an organised system for third party access to transmission and a published tariff.

Regulation 713/2009 creates the Agency for the Cooperation of Energy Regulators (ACER), which, according to the preamble to that regulation:

> "(6) The Agency should ensure that regulatory functions performed by the national regulatory authorities in accordance with Directive 2009/72/EC ... are properly coordinated, and where necessary, completed at the Community level."
>
> "(9) The Agency has an important role in developing framework guidelines which are non-binding by nature (framework guidelines) with which network codes must be in line. It is also considered appropriate for the Agency, and consistent with its purpose, to have a role in reviewing network codes (both when created and upon modification) to ensure that they are in line with the framework guidelines, before it may recommend them to the Commission for adoption."

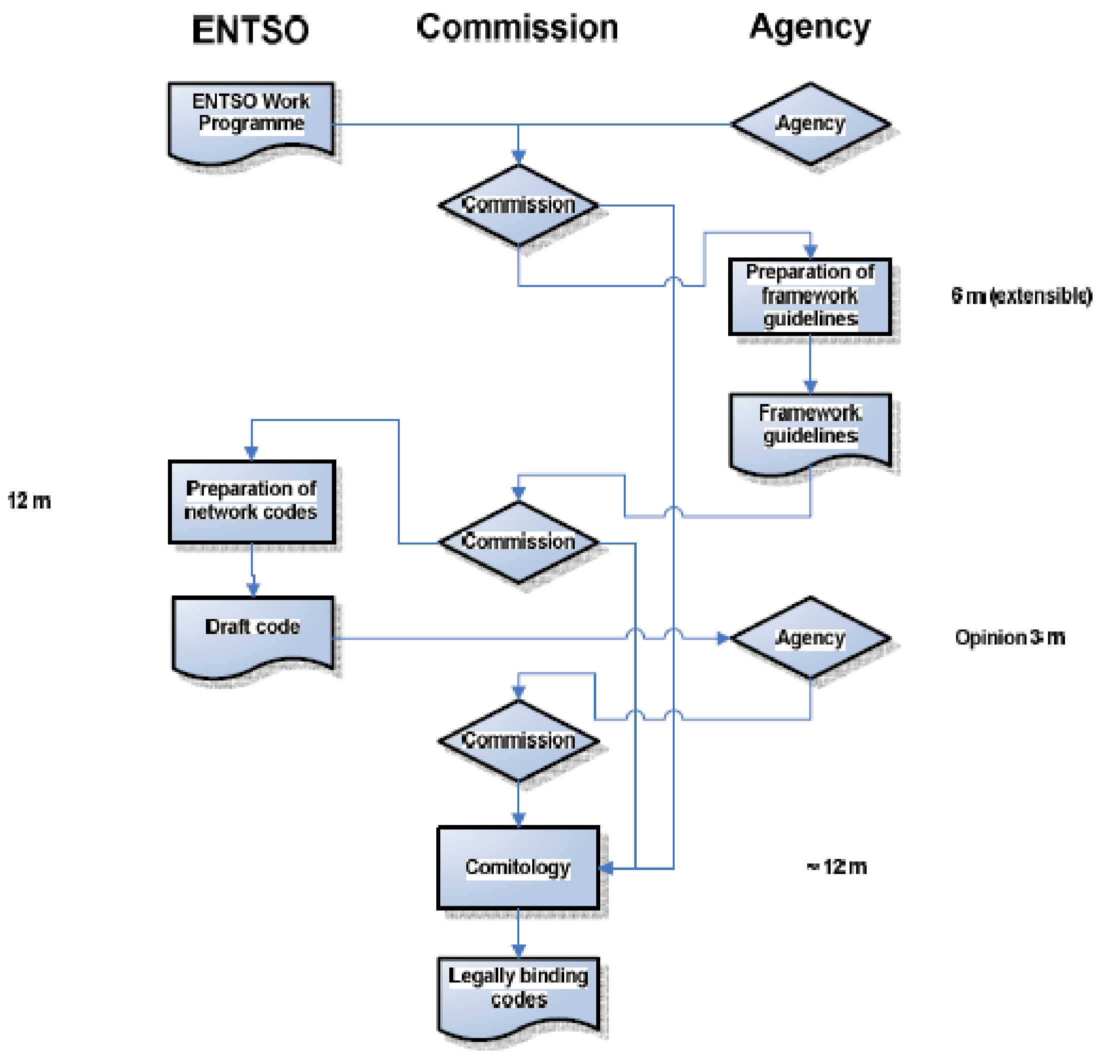
Under Article 7 of Regulation 713/2009, ACER has the power to decide on the terms and conditions for access to cross-border infrastructure. Under Article 8, ACER may decide that some aspects should lie within the competence of national authorities to be agreed bilaterally, save that ACER will take over the task if they fail to agree bilaterally in time. Terms and conditions are defined as meaning "(a) a procedure for capacity allocation; (b) a time frame for allocation; (c) shared congestion revenues; and (d) the levying of charges on the users of the infrastructure".

As a result of the creation of ACER, an agency of the EC, the European Regulators' Group for Electricity and Gas (ERGEG), which was previously set up by the EC to assist it in completing the single market, is closing down. ACER has only recently come into existence. Some of the on-going working groups and activities currently run under the auspices of ERGEG will transfer to ACER. The trade association, the Council of European Energy Regulators (CEER), will continue to exist as an organisation separate from the EC.

Regulation 714/20009 creates the European Network of Transmission System Operators for Electricity (ENTSO-E), which has responsibility for managing the electricity transmission system and for allowing and facilitating cross-border trade in electricity. All electricity Transmission System Operators (TSOs) are required to cooperate through ENTSO-E.

The network codes relating to cross-border transmission infrastructure will be the key documents regulating access to that infrastructure, since they set out the detailed procedures for access and operation of the transmission system, and thus will impact on the market. Different network codes may be needed for different parts of the EU. The ways that these codes will come into existence is set out in Article 6 of Regulation 714/2009, and places specific responsibilities on ENTSO-E, ACER, and the EC.

Figure 2.1: Process to develop Framework Guidelines and Network Codes(simplified)[8]



In particular

- The EC directs ACER to produce Framework Guidelines in relation to certain aspects of the Network Code, which must be consulted on, and are then adopted the EC if they are acceptable to them.
- The EC then directs ENTSO-E to produce Network Codes in line with the Framework Guidelines.
- ENTSO-E submits the draft Network Codes to ACER, which may require them to be amended if they are not in line with the Framework Guidelines.
- ACER then submits the draft Network Codes to the EC, with or without a recommendation that they be adopted.

[8] *From DG-ENER Public Consultation Paper, Establishment of the priority list for the development of network codes for 2012 and beyond*

- The EC may choose to adopt a Network Code recommended to it. If no Network Code is recommended, there are alternative processes by which the EC may adopt a Network Code of its own drafting.

ERGEG was active in advancing draft Framework Guidelines in anticipation of likely requests from the EC. ACER has now taken this task over and ACER has now produced a consultation draft of Framework Guidelines on Capacity Allocation and Congestion Management for Electricity.[9] This may present some difficulties in implementing any issues in this report which conflict with, or are simply outside, those framework guidelines. But further framework guidelines on other issues are being developed.

To the extent that Network Codes will set out detailed arrangements which will be integral to the functioning of cross-border markets, we can understand from this that although the processes of forming the Network Codes will involve considerable stakeholder consultation and decisions by ACER and ENTSO-E in line with their objectives, there is a role for the EC in directing the process, in that it both sets the agenda and decides whether to accept the output.

The Network Codes will have the status of legislation, and thus will be difficult to amend to reflect detailed matters that need adjustment from time to time. It would therefore be better to avoid setting in a Network Code operational details that might need such periodic adjustment, but rather have some subsidiary regulations (we use the term broadly) that are capable of rapid and frequent amendent. But it would be helpful if the process of adjusting the subsidiary regulations, and the powers to adjust them, were clearly laid out: it might be that a Network Code would be the appropriate place for that.

It has been generally understood that the internal market for electricity will be constructed in line with the Target Model. The Target Model has been created through the European Electricity Regulatory Forum, a periodic meeting of stakeholders in the industry with no legal status. The Target model is a non-binding high level description of the market, including some aspirations which may not necessarily be achievable. We discuss the Target Model in more detail below.

2.3 FRAMEWORK FOR ANALYSIS

The first objective of this project is to determine the desirability of the tradability of long-term transmission rights within the Single (European) Electricity Market, SEM. This section evaluates a number of possible objectives that these tradable transmission rights might facilitate, and draws conclusions about the extent to which these objectives can usefully guide their design and that of the markets on which they would be traded.

Objective: Promotes efficiency in the use of cross-border transmission infrastructure

This has two aspects. The first is whether Net Transfer Capacity (NTC) as currently determined is used efficiently for trading across the border. The second, and more challenging question is whether the NTC is correctly calculated, or whether, and if so under what conditions and by how much, the NTC could be increased under different methodologies and with the availability of different dispatch information.

[9] *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity, Draft for Consultation, DFGC-2011-E-003, ACER, 11 April 2011*

The first question is readily answered by observing the direction of flows and the resulting price differences across borders. If power flows from the high price to the low price area, or if there are price differences but NTC is not fully used, then the interconnector is clearly being used inefficiently. That problem is resolved by market coupling, which is a key part of the Target Model. It also indicates the importance of gathering data on the usage of the links to assess and demonstrate the extent to which they are used efficiently.

The second question is primarily empirical, as it depends on the topology of the network and of the loads and generation connected to it. In a largely radial network, standard methods of calculating NTC may give reasonably accurate estimates, but in highly meshed networks it is unlikely that the current methods, which are necessarily conservative, make efficient use of the information that is potentially available to System Operators. In the absence of that information it is difficult to estimate how large are the foregone benefits from more accurate estimates of NTC. It is clearly important to ensure that sufficiently granular data are collected to allow this empirical question to be tested. Given the conservative available capacities currently being declared, it seems plausible that there may be considerable scope for more efficient usage of the cross-border transmission infrastructure. Given the high cost, and long lead-time, for new investment in transmission lines, any reforms that facilitate greater efficiency in the use of existing lines is desirable, since it effectively provides additional transmission capacity for free.

There are multiple difficulties in delivering cross-border transmission projects. There are often environmental objections (that have, for example, held up new links from France to Spain for decades). There are potential problems if consumers on one side of the border would face higher prices as a result of more exports. And the main beneficiaries may not be the TSOs responsible for funding the investment. This last problem is being addressed by EC funding through the Trans-European Networks program, but the other problems remain. Thus any measures that reduce the need for such investment will likely overcome multiple obstacles and deliver European-wide benefits.

Objective: Promotes competition between generators across borders

Transmission links are necessary, but not sufficient, to promote competition between generators in, and trade between, different Member States. The EC has implemented some of the other necessary measures to promote competition between generators within Member States, such as unbundling, but has limited jurisdiction over the degree of concentration within Member States (unless that gives rise to evident market abuse with cross-border ramifications). Given prevailing levels of concentration in some Member States, cross-border links play an important role in reducing potential market power. The arrangements for, and management of, these cross-border transmission links will therefore impact on the level and nature of competition between generators within and across Member States. The whole point of the completion of the Single European Market is to facilitate trade between Member States and enhance competition. Designing the cross-border transmission market to best facilitate such competition is therefore clearly a high priority.

Objective: Meets the needs of generators and load customers who wish to enter into long-term supply contracts

There are many reasons why long-term contracts between generators and load customers facilitate economic efficiency, both in the market for generation and in the many downstream markets it serves. A large part derives from mutual risk reduction – generators assure themselves of a market, load customers obtain security of supply appropriate to their needs, and both obtain insurance against variations in the wholesale price. Another part of it is load-matching – facilitating efficient maintenance planning and peak load planning. In electricity markets where competition is present and generators and load customers are free to enter into such contracts, we observe high levels of contracting, 80-90+%. So long as the electricity markets had been mainly national, and such markets have generally been well internally connected with ample transmission capacity, arrangements for obtaining transmission rights have not been a factor in such contracting.

In recent years a number of markets have been linked across borders, and access to scarce transmission capacity linking the markets has become important. To the extent that long-term contracts are agreed for supply via those bottlenecks, the parties need either to assure themselves of the cost of access to the transmission capacity ahead of time, or else make suitable hedging arrangements at economic rates. Clearly some premium exists for making supply arrangements across the bottleneck, but once the cost of that is accounted for, competition ought to operate freely just as it does behind the bottleneck. If suitable arrangements cannot be made, then it is not just the fact of the bottleneck that is impeding competition, it is the also the arrangements for access to it. We see from this discussion that this objective is not actually different from the preceding one. Meeting the needs of people who wish to enter into long-term supply contracts is not, in itself, an objective. Rather, the fact that they would be able to do so is a strong indicator that the proposed market mechanism does in fact facilitate competition in generation across borders, and other transmission bottlenecks.

Objective: Tends to mitigate market power in generation, rather than reinforce it

Transmission links into a region where there is market power in generation are a conduit by which additional competition may be injected into that region – it offers load customers a greater diversity of sources. Transmission offers the potential to link up regions with concentration in generation, and offers greater diversity of choice between generators to the load customers across that region. But to the extent that a generator might purchase transmission rights that might have been the conduit for other generators to compete in its market, these rights can reinforce its market power. To the extent that market power is exercised within the territories of a Member State, it lies within the competence of the individual Member State to consider the implications of that and address it as it sees fit. But to the extent that market power affects trade between Member States, the issues that arise lie within the competence of the EC. Cross-border transmission affects trade between Member States, so this is a matter of relevance and concern to the EC. Therefore it is a relevant concern of the EC to seek to construct the market in cross-border transmission rights so that it tends to mitigate rather than reinforce market power in generation.

Objective: Facilitates required investment in cross-border transmission capacity

There is a perception that there is insufficient cross-border transmission capacity. As noted previously, it is possible that cross-border transmission capacity is being inefficiently used, so the shortage may be exaggerated. Nonetheless it is clear that the decarbonisation of generation, and particularly the requirement to increase the share of renewable electricity generation, will result in new generation in different locations that may be inconvenient for the existing transmission system. Increasing wind penetration will require increasing cross-border capacity as wind will frequently be higher in some regions than others, and stronger interconnectors will enable more customers to benefit from locally excess wind power. Local prices will become more volatile as wind penetration increases and will economically justify increased interconnection investment. Improved trading arrangements across borders should give a better measure of the congestion rents, and these give a useful indication of the benefits of increasing cross-border capacity. Long-term contracts give a better view of perceived future benefits and can also provide useful information to guide cross-border investment.

Where the economic benefits are not easily captured as revenue by the investor in the facility, the private case for investment may be undermined even though the social case is strong. One difficulty is that as transmission capacity increases, congestion rents fall, and that source of income to pay for transmission capacity falls. In general, in markets where capacity is delivered in large increments at infrequent intervals, be it airports, railway lines or electricity transmission capacity, charging for use of that facility at economically efficient price can result in insufficient income to pay for the investment, at least in the short term. Efficient short-run market pricing for transmission could therefore discourage investment. We understand that the EC has already granted derogations to the usual arrangements for transmission in certain cases of proposed private investment in new cross-border transmission capacity, presumably on the basis that without such a derogation the financial conditions for the investment to go ahead would not be present, even though the investment was economically desirable. In general, the cost of transmission is only a small proportion of the total cost of electricity, so some distortion away from perfect efficiency in the pricing of transmission could well be tolerable if it facilitated necessary investment. In sum, we conclude that it is desirable to facilitate needed investment, and adjustments to the mechanism to achieve this, if of sufficiently minor effect, are worthy of consideration. These might involve some temporary derogations for new links or more innovative burden-sharing arrangements for cross-border tariffication than those currently in place.

Objective: Avoids negative impacts on stakeholders

Regulators are usually legally obliged to take account of the welfare of the customers in their local market. Cross-border competition should move prices in neighbouring markets closer together. If trade is roughly balanced, then consumers will gain enough during periods of import to compensate for possibly higher domestic prices when exporting, but if trade is very imbalanced, consumers in the export zone are likely to face higher prices on average as a result of the expansion (although they should benefit from their ability to import and this should reduce the very highest prices and improve their security of supply). To the extent that average prices are higher for local customers, there is a risk that this will be resisted, not just by customers, but also by the regulator acting on behalf of customers. Some cross-border transmission schemes in parts of the EU have been resisted for precisely this reason. The increased profits made by local generators do, in principle, provide an income source which could be tapped to compensate customers paying increased prices, perhaps through the transmission charging regime. So it is clear that there is a risk that some customer can lose out from increased competition, and care taken to limit incidence effects will increase the political acceptability of proposals.

This can often, at least in principle, be addressed by a careful initial allocation of transmission rights so that those who lose and might object can be compensated by the revenues from these rights. It is a good principle of economics that if a change increases total welfare, it should be possible to devise a set of transfers or compensations that makes everyone better off and, as a matter of political expediency, it is important to see whether such compensation arrangements can be devised.

Objective: Limits the commercial risk of TSOs

TSOs are, in general, regulated monopolists who collect fees from users that are regulated to be in line with their predicted costs, resulting in returns on assets that are close to the cost of capital. Under incentive regulation with very limited up-side to their returns before regulatory claw-back and the risk of bearing the consequences of unprofitable investments, TSOs would typically be very risk averse. TSOs are the natural party to issue cross-border transmission rights, but they face financial risks if they oversell rights or if the interconnector fails and they are required to compensate transmission rights holders. Thus, they tend to be reluctant to risk any but very limited financial exposure, restricting the volume of rights they are willing to sell and of any compensation they may have to pay. The economic optimum is not at the point at which the TSO's risk is minimised, but rather when the TSO bears risks that would cost more if borne elsewhere. We conclude that it is not an appropriate objective to minimise the risks of TSOs, but rather to ensure that they are assigned the risks that it is efficient for them to bear, and provided with revenue streams that enable them to cover the costs of these risks appropriately. Indeed, this suggests a more appropriate reformulation:

Allocates risk to TSOs that it is efficient for them to bear, and rewards them appropriately for bearing that risk

As discussed above, this is the appropriate objective for a market mechanism for transmission trading.

Objective: Ensure that rights required to be tradable are defined so that the markets for them are transparent and likely to be liquid

Market liquidity and transparency are properties that underwrite confidence in the process of price formation and hence reduce transactions costs. Transparent markets increase the willingness of traders to trade, since risk is reduced, and thus transparency facilitates liquidity. It also facilitates efficiency, because the resulting price is a more reliable measure of economic cost. Thus transparency and liquidity are not sought for themselves, but as factors that facilitate efficiency.

Highly liquid markets are generally facilitated by commoditisation, i.e., reducing a large number of differentiated or customised items to a limited number of uniformly defined items that are widely traded. This is the reason why physical rights frequently evolve into financial rights, as the advantages of standardisation and liquidity outweigh the advantages of an individually tailored but illiquid contract. We can see this process in futures markets which rapidly replace forward or OTC markets for standardisable commodities such as copper or gold, where transport costs between markets are also modest and storage is similarly cheap. The difficulty with defining transmission rights is that there are often a substantial number of zones or nodes between which agents wish to trade, and rights defined between every pair of zones or nodes might be very numerous, and hence not very liquid. More uniform representative rights can be traded (e.g. at, or to and from, a balancing hub) and might be suitable provided the difference between the standard item and the more differentiated items actually required is reasonably predictable, at least on average over a reasonable period. The risk that the difference between the differentiated item and the commoditised item varies from its expected value is known as *basis risk*. The right objective is to find the best balance between liquidity and reducing the cost of basis risk. In summary, transparency and liquidity are not really objectives in themselves, but are amongst a number of other features that facilitate an efficient, competitive market and which may have to be traded off against other desirable objectives.

Objective: Facilitates the effective use of low-carbon generation capacity

The EU has specific objectives to reduce the carbon intensity of electricity generation. Low-carbon energy, notably renewable energy, is likely to be available at very different locations compared to the existing generation capacity, creating new flow patterns and new demands on the transmission system. Certain low-carbon energy sources, e.g., wind and run-of-river hydro-electricity, have a low marginal cost, and so tend to be used whenever they are available. Although this can increase congestion on the transmission system, and displace other generators, the situation is efficient and, under sensible market arrangements, beneficial to all. Wind output is variable, but correlations in wind output decrease with distance, so that transmission plays an important role in reducing the cost of managing the intermittency. Hydro storage in some countries is an ideal counterpart to variable wind, as it allows storage that again reduces the costs of balancing intermittency. But hydro and wind resources are often separated by transmission links, again increasing the value of that interconnection and of increasing its efficiency. The transmission market needs to be flexible enough to cope with the greater variation in flows which result from the generating characteristics of certain important low-carbon generators. But this is nothing to do with them being low carbon, it is simply a characteristic of an efficient market whose value is raised by the low-carbon generation..

Low carbon energy with higher marginal cost (bio-mass, fossil plant with carbon capture and sequestration) faces a different problem, which is its weak competitive position that justifies explicit support. That support should not be allowed to distort the transmission market. In sum, the transmission requirements of low-carbon energy are the same as any other power source, namely that transmission capacity should be built to carry its output to the extent that it is efficient to do so. This is a general issue related to investment in new capacity, not specific to low-carbon energy.

Given the envisaged low carbon targets of the EU to 2020 and beyond, market integration and cross-border energy transfers will become even more important as the penetration of intermittent and remotely located generation sources increases. Several studies[10] suggest that major cross-border transmission investment will be needed to accommodate the deployment of low carbon generation. This necessitates the development of enduring and efficient markets for cross border capacity allocation and long term price area risk hedging instruments.

Intermittency, and specifically the increasing inaccuracy of wind forecasts with longer time before dispatch, creates system operation challenges that may well impact market design, and even more, the system of support for wind. That the market mechanism handles low-carbon and intermittent generation effectively is therefore an important indicator of its efficiency. Transmission is blind to the fact that generation may be low-carbon or renewable, but its ability to handle intermittent load whose predictability much ahead of dispatch may be low is relevant. This suggests a reformulation of this objective as follows.

Accommodates intermittent generation that may be unpredictable until close to dispatch.

As discussed above, this is the appropriate objective for a market mechanism for transmission trading.

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[10] *ROADMAP 2050: A PRACTICAL GUIDE TO A PROSPEROUS, LOW-CARBON EUROPE available at* *http://www.roadmap2050.eu/attachments/files/Volume1_fullreport_PressPack.pdf*

2.3.1 *Summary Conclusions on Key Objectives*

We conclude that the following are the appropriate key objectives for a trading system in cross-border transmission capacity.

- Promotes efficiency in the use of cross-border transmission infrastructure;
- Promotes competition between generators across borders;
- Tends to mitigate market power in generation, rather than reinforce it;
- Facilitates required investment in cross-border transmission capacity;
- Allocates risk to TSOs that it is efficient for them to bear, and rewards them appropriately for bearing that risk; and
- Accommodates intermittent generation that may be unpredictable until close to dispatch.

The following are not key objectives in themselves, but rather are indicators that the above are being achieved:

- Meets the needs of generators and load customers who wish to enter into long-term supply contracts;
- Ensures that rights required to be tradable are defined so that the markets for them are transparent and likely to be liquid; and
- Facilitates the effective use of low-carbon generation capacity.

Finally, although not a key policy objective in itself, the following characteristic will reduce political resistance to the implementation of the policy:

- Avoids negative impacts on stakeholders.

2.4 TARGET ELECTRICITY MODEL

The Target Electricity Model ("Target Model") is a high level description of the market mechanisms to facilitate the Single Electricity Market. It aims at broad acceptance across stakeholders and the EC as to what they are trying to achieve. It is a high level description that can be set out on a single sheet of paper. In contrast, the Network Codes that implement it will fill many volumes. Only the schematic architecture has been laid out in the Target Model. Even then, certain aspects of the Target Model are described as "desirable" rather than being required. The Target Model emerged from the Florence Forum process, a periodic meeting of stakeholders that has no legal standing. There is no legal sense in which any of the bodies who are entrusted with specific tasks in creating the mechanisms for the single European electricity market are committed to the Target Model. Rather, it will ease the political acceptability of the way ahead if the details match the high level description with which stakeholders are familiar.

High level as it is, the Target Model is an aspiration, not necessarily suitable for immediate implementation in all parts of the EU. Some parts of the EU will require further development of their institutions to be able to implement the complete Target Model, as fully worked out in Network Codes. These areas will likely require interim Network Codes differing from those where the electricity market is fully developed.

To the extent that the present report deals with only a part of the Single Electricity Market, it is necessary to have some understanding of how the rest of the market will work. We therefore take, and are instructed to take, the Target Model as a basis for that.

There are three key parts to the Target Model:

- In relation to the day-ahead market for capacity management and allocation, the Target Model favours a market coupling approach. An important feature of the market coupling approach is that a central transmission allocator deals with national/regional transmission operators on the one side, and national/regional power exchanges on the other side. Load customers deal with power exchanges rather than with the central allocator. The main alternative to market coupling is the so-called market splitting approach, currently used for the Nordic electricity market operated by NASDAQ OMX Commodities Europe (colloquially, Nord Pool). It has a similar outcome to market coupling, although it is procedurally different. It can therefore be said that market coupling is generally the approach used in Europe at the moment for creating regional markets, one exception at present being in relation to trade on the Britain-France interconnector. An important feature of trading on European power exchanges is that they are energy-only markets.[11] TSOs can and do bilaterally arrange to trade balancing services across interconnectors.
- The Target Model requires that TSOs would be obliged to sell forward transmission capacity, but leaves open whether this should be in the form of physical transmission rights (PTRs) or financial transmission rights (FTRs). A movement to FTRs would represent a change in the present situation in Europe where most transmission trading is done on the basis of PTRs.
- The Target Model notes as highly desirable that there should be a secondary market in transmission rights, but does not require it. The Project Coordination Group (PCG) – a working group instructed by the Florence Forum – notes that financial firmness is a key requirement for an efficient secondary market in transmission rights.

Significant steps have been undertaken to establish the Single Electricity market vision. The process started with the Trilateral Market Coupling (TLC) in 2006 when the markets of the Netherlands, Belgium and France were connected. The European electricity market integration was taken further when a Memorandum of Understanding (MoU) between governments, regulators, power exchanges, TSOs and the electricity associations of Belgium, Luxembourg, the Netherlands, Germany and France was signed in Luxembourg in June 2007. The MoU agreed on the implementation of market coupling between the involved electricity markets.

In November 2010, the Central Western European Market Coupling (CWE) was launched, replacing the Trilateral Market Coupling. The CWE region is also linked to the EMCC coupling of Germany and Denmark through an Interim Tight Volume Coupling. The connection of NorNed to the CWE Market Coupling was introduced in January 2011, linking

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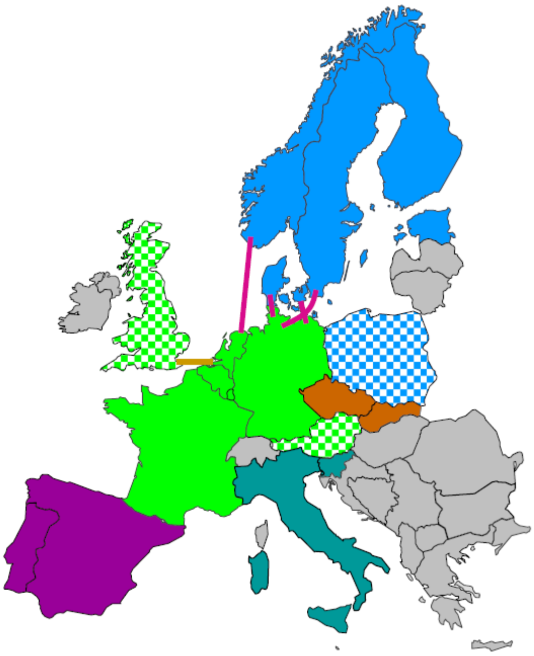
11 *The Single Electricity Market in Ireland is one important exception as is MIBEL in the Iberian Peninsular, both of which have capacity payments. The UK Electricity Market Reform White Paper expects that capacity payments may be necessary in the UK at some future date (http://www.decc.gov.uk/en/content/cms/legislation/white_papers/emr_wp_2011/emr_wp_2011.aspx)*

the Norwegian day-ahead market to the wider Central West European power market. The regional implicit auction initiatives operating to date are summarised in the figure 2.2.

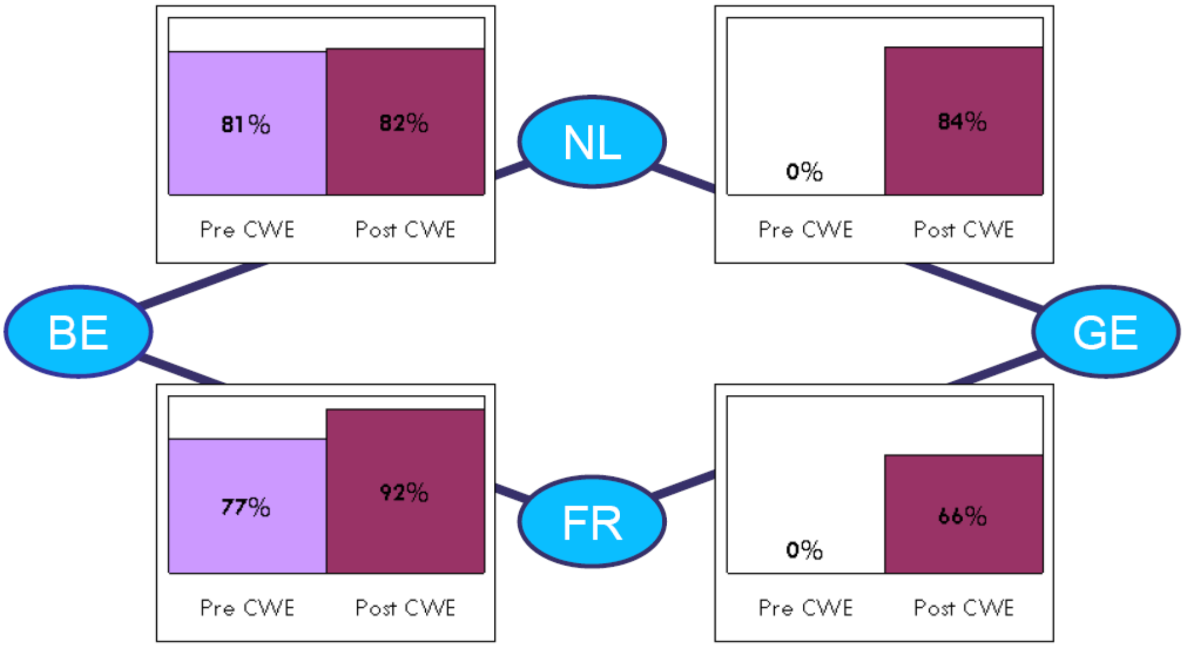
Figure 2.2: Regional implicit auctions shcemes under operation



REGIONAL IMPLICIT AUCTIONS	
CWE	Price coupling
Austria	AT price coupled to GE/CWE (no congestion)
BritNed	GB price coupled to NL/CWE
Nordic + Estonia	Price coupling, also Poland via Swepol
ITVC	Volume coupling CWE - Nordic
Italy - Slovenia	Price coupling
Mibel	Price coupling
Czech - Slovak	Price coupling

The success of the CWE market coupling is evident from the price convergence exhibited in the coupled countries since the coupling was implemented. On average, prices have converged in all CWE countries 68% of the time.

Figure 2.3: Price convergence in CWE pre and post CWE market coupling



Source: Presentation from Information Workshop on Emerging Electricity Target Models, Dundalk, 3 June 2011

The introduction of flow-based market coupling after June 2013 will further increase the efficiency of implicit auctions since the released capacity for day ahead market coupling will be significantly higher as projected in various implementation studies.[12] It is expected that the Single Electricity Market will be completed by 2015 with the gradual integration of the remaining regions into a single price coupled area. These developments will facilitate day ahead and intra-day cross-border trading, and this needs to extended to include the development of long-term arrangements for transmission rights, which is the subject of this report.

We met with representatives of ENTSO-E on 23 March 2011 to discuss progress with the Target Model. Since its creation as a more formal organisation of European TSOs on 1st July 2009, ENTSO-E has worked in anticipation of the Third Package, which came into effect with the launch of ACER on 3 March 2011. Within ENTSO-E, the Market Committee is responsible for developing the Target Model. ENTSO-E's long-term goal is to deliver the Single Electricity Market (SEM, sometimes termed the Integrated Electricity Market or IEM) by 2014, in accordance with the processes described previously.

ENTSO-E's first priority is to develop the Network Codes (NCs), after which it can concentrate on preparing its next Ten Year Network Plan (TYNP) on a more detailed and careful basis. The development of the NCs was inherited from ERGEG (which has now ceded responsibilities to ACER) via AHAG[13] and on 23rd March 2011 ENTSO-E released a comprehensive draft of the requirements of the pilot Network Code as the result of the informal process initiated during the Florence Forum in summer 2009. The pilot Network Code is a pilot in the sense of testing out the process, rather than aiming for completeness of coverage. Specifically, the pilot network code deals with grid connection with special focus on wind generation. The topics for future planned NCs are shown in the following box.[14]

[12] *CWE Enhanced Flow-Based MC feasibility report, March 2011, http://www.apxendex.com/uploads/media/CWE_FB-MC_feasibility_report.pdf*

[13] *The Ad Hoc Advisory Group of Experts that presumably was disbanded with the termination of ERGEG.*

[14] *From ENTSO-E 2010-11 Work Plan https://www.entsoe.eu/fileadmin/user_upload/_library/Key_Documents/101001_ENTSO-E_final_Work_Program_2011_01.pdf*

ENTSO-E Future planned Network Code topics

1) Operations-related code topics:

(a) Network security and reliability rules including rules for technical transmission reserve capacity for operational network security;

(e) Interoperability rules;

(f) Operational procedures in an emergency;

(j) Balancing rules including network-related reserve power rules;

2) Development-related code topics:

(b) Network connection rules;

(l) Energy efficiency regarding electricity networks;

3) Market-related code topics:

(c) Third-party access rules;

(d) Data exchange and settlement rules;

(g) Capacity allocation and congestion management rules;

(h) Rules for trading related to the technical and operational provision of network access services and system balancing;

(i) Transparency rules;

(k) Rules regarding harmonised transmission tariff structures, including locational signals and inter-transmission system operator compensation rules.

Source ENTSO-E 2010-11 Work Plan

Three ENTSO-E groups are working in parallel: one on the NCs, one on transfer capacity determination and the third on congestion management. In terms of determining Available Transfer Capacity (ATC),[15] ENTSO-E's first priority is to determine ATC for the day-ahead allocation/auction, after which it will address the determination of intra-day ATC and forward contracting. Their objective is to maximise Net Transfer Capacity (NTC) (while preserving security standards) to create the largest market for cross-border flows and hence improve the functioning of the SEM. Clear definitions of NTC are thus a pre-condition for forward contracting.

Following extensive consultation with stakeholders, on 9 February 2011 ERGEG submitted its Review of the process for drafting Framework Guidelines (FG, which deal with the capacity allocation and congestion management, CACM) to the EC. As they say on their webpage:[16]

> "The CACM FG addresses a central issue in completing the internal market in electricity, namely how (scarce) interconnection capacity is allocated and how bottlenecks in the networks are managed. The integration of national markets by means of efficient and effective use of interconnection capacity is a key step in the achievement of an internal electricity market in Europe.

[15] *ATC is NTC less Notified Transfer Flows, see https://www.entsoe.eu/fileadmin/user_upload/_library/ntc/entsoe_NTCusersInformation.pdf*

[16] *http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NEWSLETTERS/February%202011. Retrievable at date of report.*

> "The draft framework guideline addresses three timeframes of capacity allocation: forward market, day-ahead market and intraday market. Additionally, it addresses capacity calculation which is crucial to the issue of capacity allocation and congestion management.
>
> "As soon as the framework guidelines are released (foreseen for summer 2011) and on request by the European Commission, the formal period for ENTSO-E's network code shall commence. Based on these final guidelines, ENTSO-E will re-examine thoroughly the draft requirements, improving where possible and adapting where necessary. Most importantly, a formal consultation shall be launched on a new draft where stakeholders shall be requested to contribute. At the end of this consultation, the final "network code for requirements for grid connection applicable to all generators" will be released, accompanied with adequate documentation explaining the major technical choices and the anticipated benefits for the security of the electric system and the harmonisation of European practices."

The EC informs us that the present intention is that arising from this will be a single network code on congestion management, covering day-ahead, intra-day and capacity calculation.

The process of deciding how best to determine NTC is problematic in highly meshed areas, in that at present TSOs compute rather conservative NTCs using relatively aggregated information about external patterns of net injections (zonal rather than nodal detail). This appears to work reasonably well in Nordel,[17] which is less meshed than the Continent, but typically results in an underestimate of the actual NTC (but is also is in danger in some cases of overestimating NTC). The alternative flow-based methods requires considerably finer detail (dispatch plans, nodal load forecasts and adjustments to these in real time) if all interconnectors are to be efficiently used.

That model could work under full information and (voluntary) central dispatch, as demonstrated in the PJM Interconnect in the US, but there are important philosophical and practical differences between the US and EU markets that will also impact on the design of the Target Model and contracts.

The US equivalent to the Target Model is the Standard Market Design (SMD) set out by the Federal Electricity Regulatory Commission (FERC) that has jurisdiction over all inter-state electricity flows, and hence over the entire continental US, except for Texas. In contrast, ACER has nothing like the powers of FERC, individual Member States are protective of their sovereignty and progress has to be largely by consensus, and hence more evolutionary. This is particularly noticeable when it comes to requiring and sharing information about private companies such as generators, although they have to abide by their national grid codes in order to gain access to the (regulated) transmission system.

FERC gained its widespread influence because electricity in any one region in a meshed AC network necessarily impacts others, and where flows cross state boundaries, the federal government has power to act. A similar precedent has arguably been created in the EU through DG Comp's investigation of and settlement with the Swedish TSO's handling of internal congestion that had repercussions for trading over the interconnector to Denmark. As a result Sweden was required to move to at least two internal price zones – in practice it will have four zones – and reinforce its internal network. The EC could argue for the right

[17] *Nordel was founded in 1963 and was a body for co-operation between the transmission system operators in Denmark, Finland, Iceland, Norway and Sweden.*

to require timely nodal information on flows to be provided to a central authority, as these local injections and flows impact flows in other Member States and hence raise EU-wide concerns.

2.5 CONTRACTING FOR ELECTRICITY AND TRANSMISSION RIGHTS

2.5.1 *Introduction*

The direct function of long-term transmission rights for cross-border transmission is to facilitate competition between generators across national boundaries. It allows generators and load customers to manage the risk in the cost of transmission across borders over the longer term, and thus allows them to enter into long-term supply contracts, just as generators and load customers are long accustomed to contract with each other in any competitive electricity market without material transmission constraints. The tradability of such long-term transmission rights would further allow the management of the risk of entering into such long-term arrangements as circumstances change and parties may need to rebalance their portfolio of contracts. Trading of the rights would facilitate robust price formation for such rights. This would not only facilitate risk management of such contracts, but could also have wider roles in promoting the efficiency of transmission markets.

We lay out here the crucial role that long-term transmission rights play in contracting for electricity across transmission bottlenecks that define different price zones, and how secondary trading arises as an adjunct to that.

Later in the section, to facilitate understanding of how transmission rights work to provide electricity market participants with their desired products, we present some worked examples illustrating possible market workings. These examples motivate comments on how FTRs can substitute for PTRs. Finally, we briefly consider the complications presented by the increasing presence of wind power in the generation mix.

2.5.2 *The Desirability of Contracting*

Before considering contracts for transmission rights, it is helpful to consider in more detail why contracts are desirable in liberalised and unbundled electricity markets, what form they might take and why they might need to be traded on secondary markets. Transmission rights are a natural complement to contracts to sell in local markets, and allow contracting parties to hedge risks when making sales across borders or between different price zones.

In a vertically integrated industry the electricity utility buys fuel (which it can buy forward or hedge on liquid futures markets so that it locks in the price for a period) and then sells to final consumers at a price based on the cost of generation (a known fixed cost and the already contracted and known fuel costs). In an unbundled electricity industry, generators sell into a wholesale market and suppliers as well as larger customers buy in that market. Suppliers then sell on to final retail consumers, typically quoting a fixed price for some period (although spot-price linked contracts are offered in some markets and to some customers). If the wholesale price is high, the generating companies make high profits, but the suppliers who have already fixed the retail price will make low profits or losses. Conversely when the wholesale market price is low, the generating companies make low profits, but the suppliers will now make high profits. The sum of the upstream and downstream profits may be fairly stable (particularly if generators have bought fuel forward), and so if the generators issue contracts to suppliers at an agreed price, each will enjoy more stable profits and hence reduce risks and the costs of financing their activities. This activity of contracting to offset or share risks is termed hedging, in contrast to speculation, which is taking a position (e.g. buying forward) without an offsetting contract (in this case selling forward) in the hope that the spot price will rise, in which case the forward contract will make a profit and any sales can then be concluded at the higher spot price.

2.5.3 The Operation of Contracting

The simplest form of contract is a physical contract for delivery of power at an agreed price P €/MWh for an agreed volume of MW for some period (e.g. base-load for a quarter, or peak hours for a month ahead, etc). For example, in the GB market, the generator would announce to the System Operator (SO) this contracted amount (its final physical notification), and the supplier or customer holding the contract would similarly declare its purchase. If either party does not deliver or buy the notified amount they will be in imbalance, and will need to pay the relevant imbalance charges. In GB, which has a Balancing Mechanism, not a balancing market, if the generator is short he pays the System Buy Price on the shortfall, and if he produces too much he receives the lower System Sell Price on the excess (see figure 2.4 below).

One advantage of physical contracts is that as they are bilateral, they can be carefully crafted to suit buyer and seller. If the buyer has a particular load profile (e.g. he sells to domestic customers) then he can negotiate a suitable tailored product, at some cost as the generator will now need to find others to buy the difference between his preferred output pattern and that demanded, or risk selling it in a volatile spot market. Generators with a balanced portfolio of plant types (base, mid-merit and peaking) can readily offer the market portfolio, while others may only wish to offer base-load contracts. If there is a monopoly utility then it can offer individual contracts that can be adjusted as necessary – usually according to a tariff schedule for capacity, power at different times, etc.

If the market is liberalised and customers have a choice they can choose between the contracts that different generators offer. Some of these may have all the flexibility needed to handle changes in requirements, but it will be hard to compare such idiosyncratic contracts and difficult for buyers to know if they are getting a good deal. There is therefore a strong need for some transparency, which forces contracts to become standardised and easy to compare – for base load, peak hours, and possibly shoulder hours. Reporting services such as Platts collect and publish data on standard contracts in response to this demand from buyers.

These standard contracts will no longer be exactly what individual consumers want and so they will need to construct a portfolio of contracts and have the ability to trade hourly products in a power exchange to meet the desired demand profile. However, it is difficult to predict contracting needs accurately in advance and so the parties are likely to need to rebalance their portfolios by further contracting or trading their original contracts, rather than leaving it all to the day-ahead power exchange for final balancing.

2.5.4 Traded Transmission Contracts

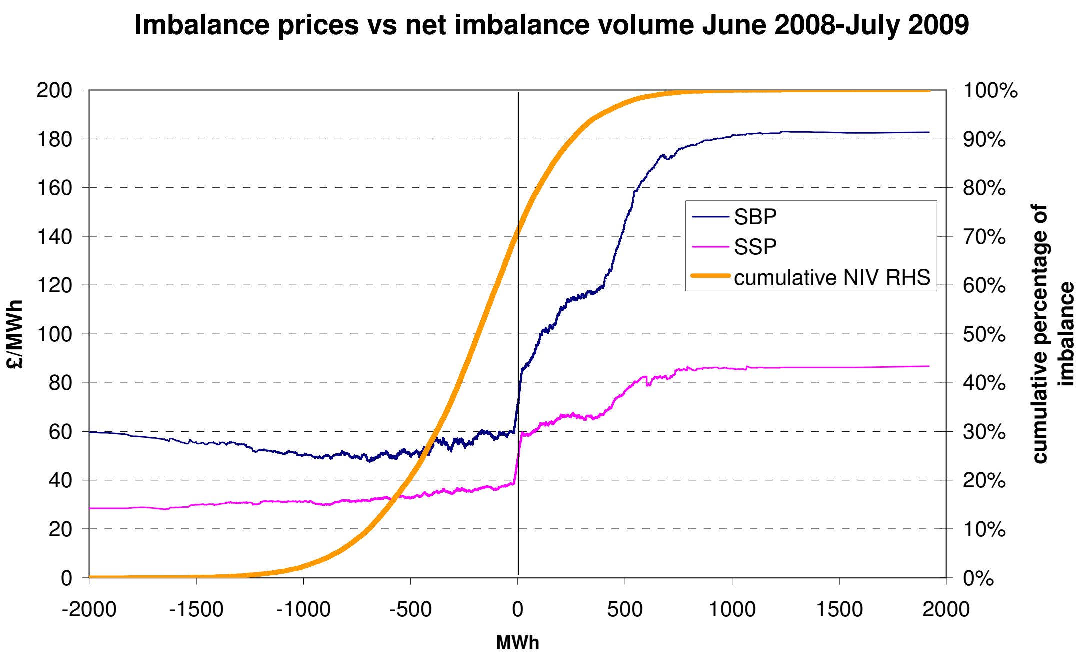
These standard bilateral contracts are traded on a power exchange or on an Over-the-Counter (OTC) market, and provide guide prices. These secondary markets provide an option for rebalancing portfolios. If a generator has sold M MW forward, and wishes to reduce this to B MW, then he could either renegotiate the contract or buy $M - B$ from some other generator, and similarly a supplier could rebalance his portfolio by buying or selling various amounts. Thus well ahead of time it may be that the supplier is happy with a certain number of base-load and peak-hour contracts, but nearer the time of dispatch, may have more accurate forecasts of demand and need to sculpt the volumes and even make up the exact load profile in the day-ahead market.

The need for a secondary market is therefore fairly clear, both to provide price discovery and as a way of securing contracts and rebalancing portfolios of contracts. The need for rebalancing and adjusting positions is a consequence of the difficulty of predicting demand and supply accurately ahead of time. Between contracting and delivery, the weather may change, generators may fail and need maintenance, transmission lines may be out of service making delivery from some plants infeasible, etc.

There is a natural evolution from reliance on an individual generator who can respond to his customers' changing needs to the more competitive situation in which standard contracts emerge and are complemented by hourly adjustments on the day-ahead power exchange. The more liquid and predictable the day-ahead market, the easier it is to manage purchases by a small number of simple contracts (base and peak) as their transactions costs will fall with standardisation and increased trading volumes, offsetting the small extra cost (primarily of risk) of meeting residual demand in the spot market.

If markets are liquid, then the price will be relatively insensitive to modest changes in the volume offered or bought (measured relative to total final demand), but in an illiquid market there may be a considerable difference between the buy and sell price for even modest volumes. This is most dramatically illustrated in the GB Balancing Mechanism, where there are explicitly different buy and sell prices, as shown in Figure 2.4.

Figure 2.4: Bid-offer spread in the British Balancing Mechanism



Source: Elexon data
Notes: SBP=System Buy Price, SSP=System Sell Price, NIV is Net Imbalance Volume

Spot and hence contract markets vary considerably in their liquidity for various often reinforcing reasons. If markets start illiquid, then trading will be costly and/or risky (with greater reliance on volatile and thin spot markets). In response generators and suppliers may choose to vertically integrate to avoid exposure to the wholesale market, in which case less trade will flow through that market and it will remain illiquid, failing to provide the transparency and ability to adjust positions that customers want. In contrast, some markets are sufficiently transparent and predictable that they encourage trade and that enhances liquidity. Thus some power exchanges, Nord Pool being the leading electricity example, have a turnover many times the underlying demand, so contracts effectively change hands several times. Others, and the GB day-ahead power exchange is a notorious example, have lower volumes, in this case as many generators are vertically integrated with suppliers and do not need to go through a market or contracting to hedge their position.

Given that the hourly profiles will almost certainly need to be adjusted closer to real time, the prompt[18] and day-ahead markets play an important role in allowing fine adjustments to be made when demand is better known. How liquid and volatile these markets are will determine how risky an imperfectly hedged contract portfolio will be. Market design can play a critical role here. If balancing is simple, has a single price for all transactions, and is liquid, competitive and well arbitraged with the day-ahead and any intra-day markets, then agents will be happier to hold and trade simple contracts and make adjustments in the spot and balancing markets. That will increase the demand for and hence liquidity of these contracts. Arbitrage works well when there are many agents able to take positions in markets, and when prices are not too unpredictable hour by hour. Large well-integrated markets work better, markets with wide access to adequate hydro storage also are more predictable over the short and medium run and also work well. Poorly designed balancing markets as in GB inhibit trade, encourage vertical integration and reduce liquidity, as do concentrated markets with weak interconnection to neighbouring markets.

One way of increasing liquidity is to create a centrally dispatched compulsory gross pool to which all generators are obliged to offer their capacity and output, and which determine a single (zonal) price for unconstrained power, as well as providing the SO with access to these offers with which to resolve constraints and deal with real time adjustments. In other cases trading arrangements, particularly for balancing, can evolve into voluntary pools provided there is a sufficient volume of generation willing to be dispatched under central control, for one side or the other of the market will typically find it attractive to make use of its services. Central dispatch should be more efficient than self-dispatch, particularly for less diversified generating companies, and so should have an advantage for at least one side or other of the market. In such cases, voluntary pools can deliver almost all the required balancing and price discovery properties of a compulsory pool.

The single hourly (or shorter-term) price for a large fraction, possibly all, of demand greatly aids price transparency and contracting. The classic form of contract in such pool markets is a financial contract, and specifically a Contract for Difference (CfD).[19] In a two-sided CfD the generator issues a contract for 1 MW each hour for a well-defined period (e.g. base-load for a quarter, or peak hours for a month ahead, etc) at a strike price, s, say. The generator then sells into the wholesale spot market and at any moment receives a price, p, say, and the supplier likewise buys from that market at the same price. The generator then pays the supplier $p - s$ per MW for that hour (which might be negative, i.e. he receives from the supplier, if the spot price is below the strike price), and each has effectively received or paid s for that MW in that hour.

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[18] *E.g. see http://www.apxendex.com/index.php?id=215*

[19] *Here we use the term CfD to apply to the general financial concept of a contract for difference, ie settlement of a difference between an agreed price and a price determined elsewhere. The CfDs traded on Nord Pool are a specific example of the general concept.*

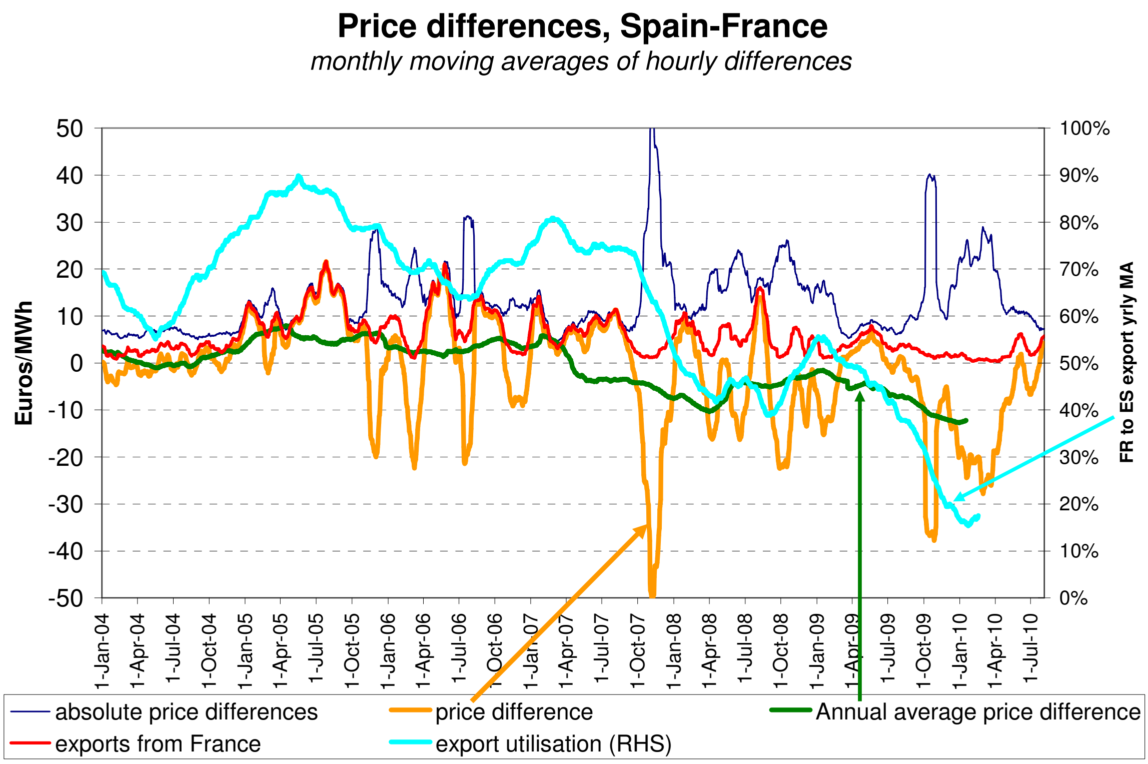
There are natural variants on this standard two-sided CfD. A one-sided CfD might set an upper price, u, in which case each accepts the wholesale price if it is below u, but otherwise the generator pays $p - u$ to the supplier. This caps the risk of price-spikes that the supplier might face.

CfDs require a well-defined market price against which to write the contracts. If the market is based on bilateral trading through power exchanges as in most of the EU, then this requires very liquid spot markets, and clearly Nord Pool meets this test and has an active CfD market. Arguably the EEX is similarly liquid, and perhaps also the APX that handles much of the trade in the Benelux coupled markets.

2.5.5 *Worked Examples 1: Physical Contracting across an Interconnector*

Consider a TSO auctioning a PTR for base-load use of an interconnector (IC) for 1 year starting on 1 Jan at an auction held on Sep 1 the previous year. To be specific, consider the French-Spanish border, whose price evolution is shown in Figure 2.5 below.

Figure 2.5: Price differences, Spain less France, centred moving averages



Sources: OMEL, Powernext

The differences in annual average prices (green line) are quite small and lie between + €10/MWh (i.e. Spain is more expensive than France, making exports to Spain attractive) and a little more than -€12/MWh (Spain is cheaper than France). However, the absolute price differences on an hourly basis (which measures the value of the option to trade from the cheaper region to the more expensive) is substantially higher – between €6 and €50/MWh on a monthly average basis, and this is essentially the value of the IC that would be received by the TSOs from day-ahead hourly auctions. Capacity is sold on a directional basis – e.g. from France to Spain and v.v., so the value of the option, but not the obligation, to export from France to Spain when Spain is more expensive is normally lower than the value of the option of being able to trade either way (except when Spain is systematically more expensive than France, as it is in some months). The range here is from zero to €20/MWh. The sum of the values of the options to export from and to Spain make up the total value of the IC shown in the graph, so the value of the Spain-France export option is just the difference between the total value of the IC and the France-Spain export value. The percentage of the time that France would export to Spain based on hourly spot price differences is shown on the RHS and arrowed. It varies from a yearly average of 90% to only 10%.

We can examine the consequences of various forms of contracting using this border as an example. The current form of contracting offered by TSOs is a PTR, in this case for the right, but not the obligation, to export 1 MW every hour of the year from France to Spain. Day-ahead the PTR would be converted into an FTR under the emerging standard of Use-it-or-sell-it (UIOSI), in which un-nominated flows would be auctioned by the market operator, MO, in the day-ahead coupled markets (hypothetically we suppose France and Spain to be coupled with UIOSI).

The case of a company contracting for power

Suppose that we are considering a base-load contract for 1 Jan 2006 to 31 Dec 2006, and suppose that the forward contract prices for base-load in the previous September are perfect forecasts of the average annual spot prices in each country for 2006 – that is €50.65/MWh in Spain and €48.13/MWh in France. It would then seem that Spain is €2.52/MWh more costly than France, and so perhaps a French generator would offer a one-year base-load contract to a Spanish company if he (or the company) could secure a one-year PTR on the interconnector for less than this cost (€2.52/MWh or €22,075/MW for the year).

However, the value of that PTR to someone who would use it for spot trading is considerably higher, as he has the option of not exporting unless the price in Spain day-ahead is higher than in France. The value of a PTR held as an option to trade throughout 2006 is €8.49/MWh (or €74,372/MW for the year). Consequently, Spanish companies wishing to gain access to a wider range of suppliers by looking across the border might seem to be unsuccessful in bidding for these kinds of transmission rights against traders, at least if they insist on physically sourcing their power from a specified French generator.

But consider a more intelligent trading strategy for that company on a particular day (replicated on all other days in the year). The French generator nominates his contracted volume into the day-ahead coupled auction on 19 July 2006 at his marginal cost, say €30/MWh, after which the French day-ahead daily average price clears at €116.83/MWh while the Spanish market clears at €55.30/MWh.[20] If the markets were for daily blocks then the Spanish company would be better off buying day-ahead in Spain at €55.30/MWh, selling his French contract into the French day-ahead market at €116.83/MWh, and releasing his PTR for exporting for its market price of zero. Instead of buying power under the original contract at the (average sunk) cost of €48.13 + the cost of the IC set by traders at €8.49/MWh = €56.62/MWh he now buys power in OMEL at €55.30/MWh and makes a profit by buying French power under contract at €48.13 and selling it at €116.83/MWh = €61.53/MWh, more than his Spanish purchase cost (on this particular day). These trading profits will cover the difference in the average cost of buying base-load French power rather than Spanish power after paying the trader's price for the IC.

[20] *Properly we should do the experiment hour by hour when the results would be more dramatic but more complicated to set out.*

In short, the Spanish company can act as an arbitrage trader in the Spanish and French day-ahead coupled markets, while having the assurance that he can always rely on securing power from the French generator and use the PTR on the IC.

Note that (in our costless world with no risk premia and perfect foresight) this is the same outcome as if the Spanish company had signed a one-year base-load CfD with a strike price of €48.13/MWh and a one-sided FTR from France to Spain (i.e. one that allows the holder to be paid the excess of the value of exporting to Spain, but not to be liable for paying if the French price is higher than the Spanish price). The cost of such a one-sided FTR would (if perfectly arbitraged) be equal to its value of €8.49/MWh, which would yield trading profits from reselling it into the coupled market auction of €8.49/MWh and meanwhile allow imports at an average cost of €2.52/MWh, giving the same result as buying a Spanish CfD with a strike price of €50.65/MWh. If the company had bought a two-sided FTR from France to Spain its arbitraged price would be equal to the average difference in the annual base load prices, i.e. €2.52/MWh, lower as the holder would be liable to make payments when France imports. So on any day the results would be different but averaged over the year it would come out to the same annual cost.

We can also work through the case in which Spain has higher prices than France. Consider the case a month later on 18 August when the French day-ahead average price is €24.87/MWh and the Spanish price is €40.99/MWh. With a liquid day-ahead market the French generator would not generate, as his variable costs are higher than the price, and instead he would discharge his obligation by buying spot day-ahead Clearly it is now attractive to export to Spain, so the Spanish company now accepts the spot French electricity and imports it, paying the French generator the agreed strike price of €48.13, and has already incurred the cost of the IC set by traders at €8.49/MWh, so the total cost is €56.62/MWh. Alternatively (and equivalently) he could not nominate the PTR and receive the spot price difference of €40.99 - €24.87 = €16.12/MWh and buy in OMEL at €40.99/MWh, at a net cost of €24.87/MWh, and then pay the French generator the difference between the strike price of €48.13/MWh and the spot price of €24.87/MWh (which the French generator now receives as well by selling spot rather than delivering on the contract), ending up as before. Arbitrage (achieved in coupled markets) means all these various routes to acquiring power are equally costly, leaving the choice to be decided by the lowest transaction costs or best contract credit-worthiness.

Thus forward physical contracts and UIOSI PTRs are equivalent to CfDs and one-sided FTRs provided the physical contracts can be readily traded in liquid markets to establish reliable prices, and provided there are liquid coupled day-ahead markets. However, financial products are less costly to trade than even standardised physical contracts and are likely therefore to create deeper and more liquid trading pools. The further advantage of liquid financial contracts is that the Spanish company can elicit offers from French as well as Spanish generators, and can bid for FTRs to match the French offers, provided, reasonably, that his buyers think that they are competing with risk-neutral and well-informed traders for their FTRs who will set the price on the IC correctly, and that the buyer is not so ill-informed that he suffers a major winner's curse on the IC auction.

The position of the TSO on the IC

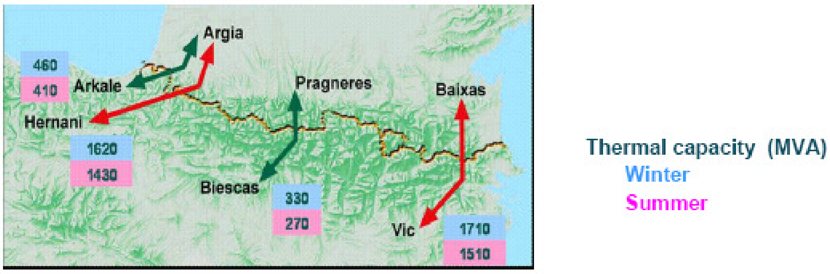
Suppose that the French and Spanish TSOs have set up a trading arm to auction off the IC and share the revenues according to some formula. Suppose that they have sold the 2006 France to Spain PTRs or one-sided FTRs at what emerges as an unattractive price – say €2/MWh instead of the actual arbitrage profit of €8.49/MWh. Provided the IC does not fail and that the TSOs have not sold more than the volume of the IC, they are perfectly hedged, because although they are liable for the actual average export value of €8.49/MWh, they will receive exactly this revenue from the price differences in the day-ahead coupled markets. True, they only made €2/MWh instead of €8.49/MWh, but they do not lose. As markets become more liquid and traders better at forecasting price differences, so the TSOs will make (on average) a higher fraction of the ex post actual profit.

More to the point, they could almost surely afford to compensate TR holders properly (at the actual price difference) from the auction revenues unless these were very poorly arbitraged and the failures happened on the worst hours. For example, the average price difference for the most expensive 24 hours (not consecutive, so exaggerating the risk) is on average (over the period 2004-2009) 3.3 times the average (and the maximum is only 5.5 over that period), which means that if the IC is unavailable for 5% of the time, 16% of the annual profits would cover the loss, assuming the IC were sold at fair value.

PTRs as Obligations or Options

Current PTRs normally work as options in that they can be used (by nominating flows on the IC day-ahead) or sold, but would not involve penalties when their value is zero and the flows are in the opposite direction. As a result the TSO cannot safely issue more PTRs in either direction that some fraction of the NTC (assuming that it is desirable to keep back some for later sale, including in the day-ahead auction). That greatly limits the extent to which companies in one country can access generators in another country, and hence limits the effective size of the market. Note that with FTRs the TSO can issue any amount of directional two-sided FTRs (e.g. from France to Spain) provided the net FR->ES is less than the NTC (i.e. 1,400 MW in 2007) and the net amount ES->FR is also less than the NTC (i.e. 500 MW in 2007), as shown in Figure 2.6 (and both are far less than the thermal capacity).

Figure 2.6: Net Transfer Capacity and Thermal Capacity between France and Spain in 2007



Spain-France NTC (Net Transfer Capacity) evolution

F–S	S-F	HORIZON
550 MW	400 MW	from 1997 to 1998
1.100 MW	400 MW	from 1998 to 2002
1.400 MW	500 MW	from 2002 to current date

(*) 550 Winter capacity France to Spain / 400 Winter capacity Spain to France

Source: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_INITIATIVES/ERI/South-West/Final%20docs/ERI%20SW%201st%20SG%20071003%20fr%20sp%20interconnection.pdf

It would be possible to make the PTRs into obligations, although that is not how they currently operate, but at that point it would surely be sensible to make them into normal (i.e. two-sided) FTRs and ensure that the day-ahead market on which they are struck provides a reliable reference price (as it surely would in a coupled day-ahead auction). FTRs would also be simpler to clear through a clearing house[21] that agents holding contracts would surely require, ensuring credit worthiness (although standardised physical contracts can also be cleared: many financial OTC contracts are cleared on Nord Pool, and physical contracts could be cleared likewise).

If PTRs were to be made explicitly obligations, they could then be netted so that the algebraic sum lay between the NTCs (e.g. -500MW < [FR-> ES] < 1,400MW) and it might then make sense to hold an auction, say in September the year ahead or whenever year-ahead contracts are signed, at the same time these power contracts are available. In liquid contract markets one can imagine a coupled auction in which power and IC physicals are simultaneously cleared subject to IC NTCs, with re-trading of these PTRs in subsequent auctions or on OTC markets, but it is far simpler to imagine this process working well for CfDs and FTRs, with the added advantage that outsiders could buy counter-flow FTRs (e.g. trading houses in places like Morgan Stanley), taking speculative positions on the future price differences, and hence increasing market liquidity.

[21] *From Investopedia: Each futures exchange has its own clearing house. All members of an exchange are required to clear their trades through the clearing house at the end of each trading session and to deposit with the clearing house a sum of money (based on clearinghouse margin requirements) sufficient to cover the member's debit balance.*

The advantage of obligations such as FTRs is that the power markets accessible to companies are immediately widened, and generators from each country can compete against each other to supply companies (or suppliers) in other countries. By offering a CfD to a company in Spain a French generator can directly compete with Spanish generators, and if Spanish generators respond to their loss of local sales by offering into the French market, their flows will net to produce the same outcome as if each had supplied into their local market. Given the concentration of generation in many EU markets, encouraging cross-border sales is surely pro-competitive.

2.5.6 *Worked Example 2: Physical Contracting under Market Coupling*

Suppose that we are considering physical contracts between zones with different prices in a market coupled system. Consider a country that has instituted zonal pricing to reflect an important constraint that limits exports from zone S to zone E. (This labelling is motivated by the fact that we will later use the example of Scotland and England within Great Britain, which are in fact treated as a single zone currently.) Consider a low-cost generator, G, in S wishing to sell to a company, L, in E. In a world of physical contracting, the generator will secure interconnector capacity ahead of time at price g, and as the best price he can secure in E is $\mathrm{E}p_E$ and if we define $c = \mathrm{E}p_E - g$, and as he is willing to sell at the bus bar at this netback value c, he will contract with the company for this delivered price $g+c$. At the time of contracting the expected zonal prices are $\mathrm{E}p_S$ in S and $\mathrm{E}p_E$ in E, with $\mathrm{E}p_E - \mathrm{E}p_S = g$ (by arbitrage, if there is no risk or liquidity premium).

If the interconnector fails, suppose that the market clearing prices move to $P_S < \mathrm{E}p_S$ and $P_E > \mathrm{E}p_E$, where the difference could be considerably greater than g as power can no longer be delivered from S, raising its price there, into E, where it depresses the price. If the TSO that has accepted the bid from G for the interconnector now pays compensation g, then G will only receive P_S instead of the higher sum $\mathrm{E}p_E – g$. If the TSO had been liable for liquidated damages the payment for non-delivery would be $P_E - P_S > g$ and the TSO would expect to receive a premium for providing insurance against failure, so that $g > \mathrm{E}p_E - \mathrm{E}p_S$.

Could G have insured against such an outcome if the TSO refuses to pay compensation? If there are zonal CfDs, then G could sell a CfD in S at a strike price s_S which might even be at a premium to $\mathrm{E}p_S$, e, say, as buyers in S might be willing to pay a premium e for certainty, and to hedge their retail sales. G could also buy a CfD in E with a strike price s_E, this time possibly have to pay a small premium, which, with luck, might cancel out the S premium (if the CfD required a premium payment of e on $\mathrm{E}p_E$).

Now consider the same interconnector failure again, with initially $\mathrm{E}p_E - \mathrm{E}p_S = g$, but now the CfD is S pays P_S-s_S and compensates for receiving only P_S in the local market, while the English CfD pays out P_E-s_E while G has to buy power in E at P_E while receiving only s_E so effectively G has sold his power at the originally contracted price s_S.

It would seem that if there are liquid zonal CfD markets then the TSO does not have to compensate G for failure to deliver. However, this is not correct, for there will be parties damaged by the failure. If everyone who buys electricity in zone S holds a CfD with a generator there, there may be no willing holder of the CfDs that G wishes to issue to hedge the cross-border trade, in which case G would be locally un-hedged. If G is successful in hedging cross-border trades by issuing a local CfD then some other generator will suffer from the fall in local prices. The only other alternative is for some trader to be willing to issue FTRs and be exposed to the risk of failure and a consequential loss, which would have to be compensated by a risk premium, effectively an insurance contract against the failure. From an incentive and arguably regulatory viewpoint, the TSO would seem better able to manage such risks and ought therefore to be required to offer them (and to be adequately remunerated to handle them).

The correct solution would be for the TSO to pay out the difference in zonal spot prices, P_E - P_S. Then G would receive P_S locally for generating but have to pay P_E in E to satisfy his delivery contract, which pays net to him Ep_S while he receives P_E - P_S from the TSO, leaving him as before with net s_S. The advantage of a FTR is now immediately obvious, for one liquid financial contract on the spot price differences hedges the forward contract G has with L, while it requires two zonal CfDs to hedge if the TSO is not willing to bundle up what is in effect an FTR with the forward interconnector contract by paying the spot price difference in the event of failure. Indeed, the FTR insures against any local price deviations from expectations, so is better than a contract with the TSO that only pays out in the event of a failure or other well-specified event.

The advantage of an FTR is that it can be combined with a CfD in the delivery zone (or an OTC contract with L), giving two more tradeable instruments than a PTR and a physical OTC contract with L, and the FTRs should be more liquid than PTRs.

The Present Situation in Great Britain

At present Great Britain is treated as one zone, albeit that there is often congestion on the two transmission links passing through the lightly populated borderlands of S(cotland) and E(ngland) on the Cheviot constraint. If the buyer and generator hold a contract at gate closure and this cannot be satisfied because of the Cheviot constraint, then the SO must constrain off (or secure balancing down services) in Scotland and constrain on generation (or secure balancing up services) in England, whether or not the Cheviot constraint is operating or fails; in either case it has effectively been oversold. If zonal pricing were to be introduced and the Cheviot constraint were the boundary of the zones, then if that constraint binds, S and E will have different prices as above. The present system of final physical notifications before gate closure would presumably need modification for G selling to L across the constraint, and in the spirit of physical contracting, would presumably need a physical transmission right, PTR. It would seem desirable for these to morph into financial contracts, but that might also need a redesign on the balancing mechanism to create a single price for short-term (intraday) power (which would also be desirable).

Let us consider whether an FTR could be combined with the current British Electricity Trading and Transmission Arrangements (BETTA). Suppose G plans to sell M MW to L and has an FTR for M MW. If selling across the Cheviot border requires the possession on an FTR, and these have been issued to ensure a feasible (secure) dispatch, then all FPNs (Final Physical Notification) can be accepted in S and E and the system should balance, although presumably the spot prices will differ if these are determined only by the balancing market (and at present the balancing market is small and illiquid in that prices move considerably with modest volumes of imbalance as shown in figure 2.4).

Zonal markets (and contracting more generally) would benefit from greater liquidity, and if the forward contracting is restricted to a limited number of contracts (base, peak) then the day-ahead market would trade the (half-) hourly products need to create shape, and might become more liquid. In that case, generators might find it attractive to hand over dispatch to the SO to allow a more efficient use of their plant, which might support a more liquid market, at least if the markets were adequately competitive. In less competitive cases where generators are trying to deter entry, the generators might prefer the opacity of the current contracting arrangements and resist such moves.

2.5.7 *Complications Because of Wind*

The problem increasingly faced by SOs is that wind in any future hour is hard to predict and, assuming it takes priority in dispatch (either legally or because it can undercut any other generator), the remaining ATC is unpredictable until a few hours ahead of time. Thus in a weekend in February 2011 unusually high wind (20 GW rather than 5 GW the previous year) in Germany forced TenneT as the relevant TSO to block commercial cross-border flows in CWE (*Argus Power Europe* 17/2/11), and remove almost all the ATC of 2 GW between the Netherlands and Germany to retain security margins. Such events are likely to become increasingly frequent, and raises the question of whether they would undermine the TRs.

For conventional generation trading across borders, wind creates no (financial) problems. Consider the case above with a generator D in Germany selling to a company N in the Netherlands and holding an FTR on Germany-Netherlands. If wind displaces the D-N trade, then D is compensated through the FTR by the fall in price in Germany and the rise in price in Netherlands, and D can sell in Germany while N can buy in Netherlands and their revenues and payments remain as before. The SO will pay-out the now higher price difference across the interconnector but will receive the price difference from the extra wind that has flowed.

That raises the question about the contracts held by wind and whether they or someone else pays for the extra costs of exporting the surplus wind. Suppose, as seems relevant in North Germany and Denmark, that the wind farms have effectively firm access and hold FITs (Feed-In Tariff) with a fixed price, *f*. They receive *f*/MWh regardless of their zonal price. The counterparty to the FITs (some agency who has the authority to recover the subsidies from charges to final consumers) should receive the zonal price in the zone in which the wind is located, and pay the FIT price, recovering the difference from consumers. If the interconnector would have been constrained in any event, the zonal price in the importing zone will be unaffected, and there are no external repercussions. If the interconnector would normally be unconstrained, but wind now causes it to be constrained, supply into the import region will have increased, and the price there will have fallen, with a net gain to that zone (generators exposed to the spot price will receive less, exactly equal to the gain of the consumers these generators supply, and in addition consumers can consume a little more at a lower price than they expected).

TSOs are likely to be reluctant to expose themselves to potentially large commercial risks that reduction in ATC might cause, and they are likely to respond by reducing the ATC that can be forward contracted, and/or limiting the duration of any contracts to a year or less, despite the willingness of buyers and sellers to contract for longer periods. Assuming that it would be desirable to facilitate cross-border trade and to encourage the release of as much capacity as possible, and indeed to provide incentives for building additional profitable capacity, how should these risks best be borne?

One possible solution is to allow TSOs to use the revenue from zonal price differences to compensate for forecasting errors. In effect the TSO sells *M* MW of capacity in an FTR auction ahead of time, and then finds the need to buy back *B* MW for short-term balancing actions. These might be netted off the auction revenue, on the argument that although they could be deemed to be balancing actions to be charged to wind, with FITs these are effectively passed back to consumers, who would have been the beneficiary of the auction revenues anyway.

However, the more satisfactory solution is to address the heart of the problem, which is the unsatisfactory method of computing NTC ahead of time, although we understand that this might be of limited effect with a zonal market design.

2.5.8 Additional Worked Examples

In the following examples, we may refer to "a local power exchange". But the reader should not conclude that this is a necessary feature of how FTRs should work. They can work with bilateral trading, provided that there is a reliable reference price for the FTRs.

Contracting within a price zone

G has a marginal cost of m and sells M MW to L_A one (or more)-year base at a contract price P, by issuing a CfD with a strike price of $P > m$ to L_A. When the spot price is $p_A > P$, G offers to sell in the PX at m and L_A bids to buy in the same PX at the limit price L. If the market clearing price is $p_A > m$, G supplies into the market and receives p_A and L_A buys at p_A. In addition G pays L_A the sum p_A - P on the CfD thus ensuring that the original contractual price is honoured through the financial CfD. If $m < p_A < P$, G sells in the PX at p_A and L_A buys at p_A but L_A pays G the sum P-p_A on the CfD with the same effect. If the market clearing price is $p_A < m$, L_A buys at p_A as before and the CfD is settled, but G does not need to generate and makes an extra profit m - p_A.

The most obvious credit risk is that L_A may be a supplier who is selling to customers on shorter-term contracts, and who may decide to switch if the spot price falls systematically below P, in which case L_A's contract is out of the money and he may go bankrupt. This can be addressed by marking the CfD to market on the day's closing price for the remaining base load contract price.

To give a numerical example, suppose G has a marginal cost of €30 (all prices per MWh). G sells 100 MW to L one-year base at a contract price P = €40, by issuing a CfD with a strike price of €40P. G offers to sell 100 MW into the PX at €30 and L bids to buy 100 MW at the limit price (e.g. €9,999) but the market clearing price p_A = €25. The offer is not accepted, so G does not generate, but L_A buys the 100 MW at €25 and pays G €40-25/MWh = €15. G has therefore made a profit of €15/MWh instead of his expected €10/MWh. If the MCP were €50 he would generate, sell at €50 but have to pay out on the CfD €10, effectively selling at €40 and making a profit of €10.

Contracting with a load in another coupled price zone via PTRs

G sells M MW to L_B one-year base at a contract price P, by issuing a CfD with a strike price of P to L_B. He buys a PTR for M MW from A=> B for t, presumably because P-t is more favourable than contracts he can strike at home. As before G offers M MW into the coupled market at marginal cost m, and L_B bids to buy on the other side of the border M MW at the limit price L_B but actually pays the market clearing price p_B.

If $p_A > m$ then G is dispatched, and receives p_A in A. If $p_A < m$ then he makes extra profit m - $p_A > 0$, but does not generate.

If $p_B > p_A > m$ then L_B secures power at p_B in B and the same CfD transaction ensures that L and G transact effectively at P, while G receives P-p_B per MW from the CfD and p_B - p_A from the PTR and so effectively receives P-p_A per MW in B, and p_A in A to make up the full P and profit $P – m$. If $p_A < m$, G earns profit P-$p_A > P – m$.

If $p_B < p_A$ then G secures power at p_B in B and the same CfD transaction ensures that L and G transact effectively at P, while G receives P-p_B per MW from the CfD but zero from the PTR and so effectively receives P-p_B > P-p_A per MW in B, and p_A in A to make up $P + p_A$-$p_B > P$ (and more if $p_A < m$). There is no credit risk on the PTR but the normal CfD credit risk in B remains (possibly made worse as the foreign buyer may be less familiar to G).

Contracting with a load in another coupled price zone via FTRs

G sells M MW to L_B one-year base at a contract price P, by issuing a CfD with a strike price of P to L_B. He buys an FTR for M MW from A=> B for $T < t$, because he is no liable for some downside. As before G offers M MW into the coupled market at marginal cost m, and L_B bids to buy on the other side of the border M MW at the limit price L_B.

If $p_A > m$ then G is dispatched, and receives p_A in A. If $p_A < m$ then he makes extra profit m - $p_A > 0$, and does not generate.

If $p_B > p_A$ then L_B secures power at p_B in B and the same CfD transaction ensures that L and G transact effectively at P, while G receives P-p_B per MW from the CfD and p_B - p_A from the FTR and so effectively receives P-p_A per MW in B, and p_A in A to make up the full P with profits as above.

If $p_B < p_A$ then he secures power at p_B in B and the same CfD transaction ensures that L and G transact effectively at P, while G receives P-p_B per MW from the CfD but has to pay, as his revenue from the FTR is p_B - $p_A < 0$, and again effectively receives P-p_A per MW in B, and p_A in A to make up the full P. There is now a credit risk on the FTR as this requires G to make a payment, which is however fully covered by the CfD in B, so again there is only the normal CfD credit risk in B.

In short, FTRs do not seem to introduce any additional credit risks compared to CfDs, provided of course that the FTR is firm.

2.6 Conclusions on Desirability

In this report, we have set out the important role that long-term transmission rights can play in facilitating competition between generators across borders. Long-term contracting plays a major role in competitive electricity markets, and long-term electricity transmission rights are the glue that enables that competition to be extended across borders with scarce transmission capacity. The mere existence of such rights is insufficient; the way in which rights are constructed and traded will have an important effect on the effectiveness of that capacity. In particular, the use of PTRs when combined with conservative approaches to measuring Available Transfer Capacity (ATC), without any netting, are likely to stifle the extent of trade across boundaries. On the other hand, FTRs (constructed as obligations) automatically allow for netting (FTRs constructed as options are more like PTRs with UIOSI). Moreover, financial contracts are superior to physical contracts in encouraging liquidity, market transparency, clearing house credit assurances, and lower transaction costs.

Our conclusion is that in all areas an appropriate construction of a market for tradable long-term transmission rights is capable of delivering advantages in all six areas of key objectives that we identified, and that these rights should be financial, not physical. There are some areas where there will be political resistance to change, as some stakeholders are at risk of negative impact. Some of these are market insiders who profit from a lack of transparency in the market. Others are certain consumers, who live in low price electricity zones, and whose average price might go up if their captive low cost suppliers are better able to export. In principle, these consumers are capable of being compensated, although practical arrangements need further consideration, and are ultimately a matter for individual member states as to whether they feel a need to implement such arrangements. Distinctive arrangements will be required for merchant links, and also for sub-sea links.

In the following table we summarise the advantages and disadvantages of tradable long-term transmission rights against the six key objectives we have identified.

Objective	Advantages	Disadvantages
Promotes efficiency in the use of cross-border transmission infrastructure	Effective mechanisms for allocating long-term transmission rights can facilitate increased efficiency in the use of transfer capacity	
Promotes competition between generators across borders	The ability to better to facilitate greater competition across borders is the main advantage of trade. The degree of advantage will depend upon the arrangements.	Some stakeholders are at risk of negative impacts from increased competition, albeit arrangements can in principle be made to protect their positions without damaging the market. Some market insiders who profit from lack of transparency may also be resistant to more competitive arrangements.
Tends to mitigate market power in generation, rather than reinforce it	In general increased competition should mitigate market power.	Specific arrangements may be needed to limit the ability of actors with market power to abuse their position to frustrate the competitive objectives, of which the most important is preventing capacity withholding – e.g. by Use-it-or-sell-it in the case of PTRs.
Facilitates required investment in cross-border transmission capacity	Robust price formation for several years into the future provided by long-term transmission rights will help indicate the borders most in need of investment in capacity.	Private investment in transmission capacity may require derogations from market arrangements, or supplementing from regulated revenue streams.
Allocates risk to TSOs that it is efficient for them to bear, and rewards them appropriately for bearing that risk	TSOs can efficiently be made to bear the (modest) additional risks in providing transmission rights, and unforeseen costs can be passed through to end users by the regulator, limiting downside risk.	TSOs are likely to be resistant to bearing additional risks, even if it is efficient and possible for them to do so. Undersea and merchant links may not be able to bear the additional risk without access to regulated revenue streams. Regulators may resist using interconnector revenues for compensating for outages.

Objective	Advantages	Disadvantages
Accommodates intermittent generation	Solutions exist for accommodating wind efficiently.	These solutions require providing more information and allocating more responsibility to supra-national dispatch. They may make renewables subsidies more explicit, which may be politically uncomfortable.

3. TRANSMISSION RIGHTS ARRANGEMENTS, ANALYSIS AND INTERNATIONAL COMPARISONS

3.1 INTRODUCTION

This Chapter looks at a number of characteristics of transmission rights from both a theoretical and practical perspective, presenting the relevant experience of existing transmission markets. When relevant, we analyse the details of transmission rights arrangements in three market structures:

- **Bilateral markets with PTRs** (Physical Transmission Rights) such as the ones currently operating in Europe and envisaged by the Target Model. As a practical reference case we use the England-France Interconnector (IFA)
- **Locational marginal pricing markets with FTRs**[22] (Financial Transmission Rights) as have been applied in the US and especially in the PJM Interconnection market, which extends over 12 states in the East Coast and Midwestern area of the USA
- **Zonal Marginal Pricing** (market splitting) market arrangements and in particular the Nord Pool with CfDs[23] for interzonal congestion hedging

The aim of this chapter is primarily to present the analysis to understand the issues, and assemble the fact base as evidence, and to support specific conclusions. Conclusions are presented in the following chapter.

3.2 COMPARISON OF PTRS AND FTRS

According to the Target Model, transmission rights should either be in the form of

- Physical Transmission Rights (PTRs) and granted as options with the condition to use-it-or-sell-it (UIOSI), or
- Financial Transmission Rights (FTRs), in which case they could be either options or obligations.

In ACER's Draft Framework Guidelines on Capacity Allocation and Congestion Management for Electricity (11 April 2011) which is a draft for consultation, it proposes the requirement that the rights available on any specific border should be limited as follows (para 4.1):

> "PTR shall be defined as options and subject to UIOSI. The CACM Network Code(s) shall define the nature of FTR in terms of options or obligations. Hybrid solutions, mixing PTR and FTR on the same border, shall not be implemented. The CACM Network Code(s) shall also foresee a harmonised set of rules for borders where PTRs with UIOSI are applied and a harmonised set of rules for borders where FTRs are applied."

In practice, the distinction between PTRs and FTRs is not always clear: given that the ultimate goal of any type of transmission right is to facilitate trading between different

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[22] *J. Sun, 2005,"U.S. Financial Transmission Rights: Theory and Practice," Working Paper 05008, Department of Economics Working Paper Series, Iowa State University.*

[23] *That is, the specific CfD contract traded on Nord Pool, not CfDs in general.*

nodes/zones without the exposing the right holder to the risk of congestion costs, the practical arrangements required to make this work results in some convergence.

3.2.1 *Physical Transmission Rights*

PTRs (Physical Transmission Rights) enable the execution of bilateral supply contracts between a generator and a load customer over a congested line. A right comprises a fee paid for the right to nominate the power to be transmitted via the link. The amount of rights issued must be less than or equal to the capacity of the link.

Within the European context, trading parties must hold PTRs for the relevant interconnectors in order to engage in cross-border bilateral trading, otherwise they would face whatever local penalties exist for generating or demanding capacity in imbalance in the corresponding local markets. Consequently, PTRs have a physical interpretation; where they are used, without them no cross-border bilateral trading can take place, and if nominated the holder needs to physically deliver the electricity either through dispatching its own units and/or buying the power from its regional power exchange (PX). Failing to do so results in imbalance penalties.

PTRs may have a use-it-or-sell-it (UIOSI) condition attached, which implies that in case of default of nominating the right to a despatched generator, the right will be automatically resold. Inherently, a PTR is defined for the capacity of an interconnector (flowgate) or for the direct links between two neighbouring countries/zones. A PTR is directional, in the sense that for example a PTR from England to France is a separate right from a PTR from France to England.

TSOs give the original PTR owner the total financial resale value of capacity, subject to any transaction charges. In the case of an explicit auction for the right, this is equal to the clearing price of the auction in which the directional capacity is resold (which will be zero if the flow is the other way. For PTRs with UIOSI, in case of non-nomination and implicit auction the day-ahead price differential is only paid if it is in the same direction with the definition of the right.

3.2.2 *Financial Transmission Rights*

Financial Transmission Rights (FTRs),[24] whether options or obligations, are, briefly, a claim on the congestion surplus created through the market coupling process; it is *de facto* assumed that market coupling and implicit auctions are in place.

We can explain this in full as follows. Many coupled electricity markets operate an implicit auction for the interconnection to decide which generators should despatch in each market, as a result of which a market clearing price is established in each market. If the interconnectors joining them are adequate to make any transfers required, the prices in the two markets will equalise. But when the interconnectors are used to capacity, and would carry more if they could, then a price difference will persist between the two markets. This situation is called congestion, and the price difference is called the congestion surplus. It reflects the value of access to the interconnector at that time. An FTR, therefore, is a right to claim a sum of money equivalent to the value of the congestion surplus. If you are a generator located in the low price area, you are indifferent between actually exporting into the high price area, or selling at the lower price and taking the value of the FTR. If you are a

[24] *W. Hogan, 1992, "Contract Networks for Electric Power Transmission," Journal of Regulatory Economics*

load customer in the high price area, you are indifferent between importing from the low price area, or buying in the high price area and earning the value of the FTR. Thus an FTR is equivalent to a financial product that is equal in value terms to having access to the interconnector. But it only works well to the extent that robust market prices are established on either side of the link, and there is a coupling process to link the two markets.

The definition of FTRs is always from one price zone (which, in the case of nodal pricing, would be at the point of injection or source) to another price zone (again, in the case of nodal pricing at the point of withdrawal or sink) and is directional. An FTR operates like a financial instrument and entitles the holder to claim the price differential between the sink and source. An FTR can be defined as an obligation, in which case the payout can be either negative or positive depending on the directional definition of the FTR and the sign of the price differential between sink and source. Alternatively it can be defined as an option, in which case it only has a payout if there is a gain, i.e., if the price at the sink is lower than the source price then the option payout is zero. In this sense, FTR options are similar to PTRs with UIOSI.

FTRs have no physical interpretation and are disconnected from the energy market trades. The holder of the FTR receives the payout irrespective of whether he participates in the energy markets (assuming that the FTR is firm or there is no *force majeure* in effect suspending the FTR).

A financial intermediary can construct a financial instrument that operated financially in identical fashion to an FTR. But it is erroneous to see this as precisely the same as a FTR issued by a TSO. A key distinction is that an FTR issued by a TSO is backed by capacity. A purely financial product is likely to be priced on actuarial considerations, and thus the quantity offered for sale will depend on the price they are sold at. In contrast, a TSO is likely to issue a specific quantity of rights and auction them, resulting in a price based on the quantity available. This is likely to result in a TSO-issued FTR being better value, as the TSO is automatically hedged, while other issuers, lacking that hedge, will require a higher margin to cover the risk, and so will need to restrict supply to achieve the required risk premium. The specific rules on firmness and *force majeure* would tend to be related to physical considerations for the TSO-issued right, but may be different in the case of a purely financial product.

An FTR, seen as a financial product, is a specific case of a financial product known generally as a contract for difference (CfD), a financial product which insures against price differences in different markets. For the Nord Pool, a specific financial product is traded, which is another specific form of CfD, and described as such; financially, the Nord Pool CfD is equivalent to an FTR. But these are not TSO-issued rights. Nord Pool CfDs are traded as futures in the NASDAQ OMX exchange.

Nord Pool introduced its CfD contracts in 2000. The payout of a Nordic CfD is similar to a FTR obligation, but the Nordic CfDs are defined between the Nord Pool price areas and the System Reference Price, which is equal to the unconstrained System Marginal Price (SMP) of the Nord Pool. The exchange-listed CfD-contracts are between the System Reference Price and Copenhagen (Eastern Denmark), Århus (Western Denmark), Helsinki (Finland), Stockholm (Sweden) and Oslo (South-Eastern Norway) and the newly establish Swedish price zones of Luleå, Sundsvall and Malmö. There are CfD contracts for months, quarters and the three nearest calendar years.

The experience in Nord Pool suggests that CfDs have successfully provided hedges of area price risk for the market participants, although these are not issued by the TSO. Some important advantages of CfDs over FTRs include the following:

- They are continuously traded without the need for centrally organised re-configuration auctions
- The vast majority of the CfD trades (OTC and exchange listed) are cleared through the NASDAQ OMX thus minimising counter-party risk
- Their durations match exactly the energy contract durations irrespective of the available physical transmission capacity
- They are privately and exchange administered

On the other hand, it should be noted that the Nordic system is almost a radial system with only a limited number of price zones. It is therefore questionable whether, in meshed systems with large number of price areas, the liquidity of CfDs would be satisfactory. In fact, in US nodal markets there have been no exchange traded CfD products to date although there is no institutional barrier for these market to develop.

In the subsequent sections, we analyse a number of characteristics of transmission rights such as allocated volume, duration, option/obligation definition and financial firmness. In this section, the focus is placed on examining how cross-border and cross-county bilateral trading would take place under different transmission rights definitions.

3.2.3 *Cross-border Bilateral Trading with PTRs*

Whether the day-ahead available transmission capacity is allocated through explicit or implicit auctioning is an issue that is analysed in Section 3.4. For the purposes of our analysis we will assume that both methodologies are equivalent.[25] As a reference case to examine cross-border bilateral trading with PTRs, we will refer to the England-France interconnector.

Interconnexion France-Angleterre (IFA)[26] is a high voltage DC link interconnecting the English and French transmission systems. The interconnector has a capacity of 2,000MW and supports transmission of electricity in both directions. It has been operational since 1986, allowing cross-border trade of electricity. It is jointly operated by National Grid Interconnectors Limited (NGIL) and Réseau de Transport d'Electricité (RTE). Historically, the flow has been mostly, but not entirely, from France to England. For example, in 2006, 97.5% of transfers were made from France to England, accounting for about 5% of total electricity available in the UK. The interconnector comprises of four 500 MW lines. Link availability is deemed satisfactory, being consistently above 93% for the past 5 years.[27]

To be able to use the interconnector, a user must go through a specific application process and be deemed eligible by the operators.[28] The way capacity on IFA is allocated to market participants is through explicit auctioning of PTRs, described on IFA as capacity units. The auctions are organised by the operators. Each capacity unit has an associated direction (France to UK or UK to France) and a specified operation timeframe it covers. Each contract day covers the 24 hours from 00:00 to 23:59 (all timings are in CET). Holding one capacity

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[25] *As should be the case in a two node interconnection under perfect competition and perfect foresight*
[26] *National Grid, 2009,"IFA User Guide and Capacity Management System FAQ"*
[27] *National Grid,2010, "Interconnexion France-Angleterre Performance Report 2009-2010"*
[28] *National Grid, 2009,"IFA Access Rules, Issue v. 7.0"*

unit entitles the holder to use 1 MW of the interconnector's capacity in the specified direction for the specified time period. The auctions can be split into three levels.[29]

- Auctions for long-term capacity units. These are held periodically offering capacity units for:
  - A calendar year
  - A financial year
  - The winter (October-March) or summer (April-September) season
  - Each calendar quarter
  - Each calendar month
  - Each weekend
- Auctions for day-ahead capacity units are held for every day. The auction takes place "day-ahead", between 09:40 and 10:00 on the previous day.
- Auctions for intraday units: These are to allow capacity traders to optimise their positions and react to unexpected events during the day. Two intraday auctions are held. The first is held in the previous day between 19:00 and 19:30 and auctions units covering the hours 00:00 – 13:59. The second is held on the same day between 08:20 – 08:50 and auctions units covering the hours 14:00 – 23:59.

The typical split of capacity offered between the different auctions is:

- 45% of total link capacity is offered in long-term year auctions
- 45% is offered in long-term inter-year auctions and,
- 10% is reserved to be released in the corresponding day-ahead auction.

A user that acquires capacity units in an auction may relinquish them for use by other eligible users in the secondary market as described in Section 3.6.

If a unit holder does not nominate some long-term units he holds for a contract day, he loses the right to use them. Those unused units are subsequently released in the day-ahead auction. The original unit holder is paid for his unused rights according to the clearing price of the day-ahead auction (use-it-or-sell-it or UIOSI). In case of implicit auctioning, the holder of the non-nominated transmission rights would be paid the area price difference resulting from the market coupling. Conversely, unused units acquired in a daily auction are subsequently released in the intra-day auction, but the original holder is not remunerated (use-it-or-lose-it or UIOLI).

In summary, the amount of capacity to be released in each auction is calculated in the following way:

- The amount of capacity released in long-term auctions is typically fixed.
- The amount of capacity released in the day-ahead auction is again fixed but the Operators also include any unsold/unused long-term units and any extra capacity that can be made available through the netting of already submitted long-term nominations.

[29] *National Grid, 2010, "IFA Long Term Auction Timetable 2011"*

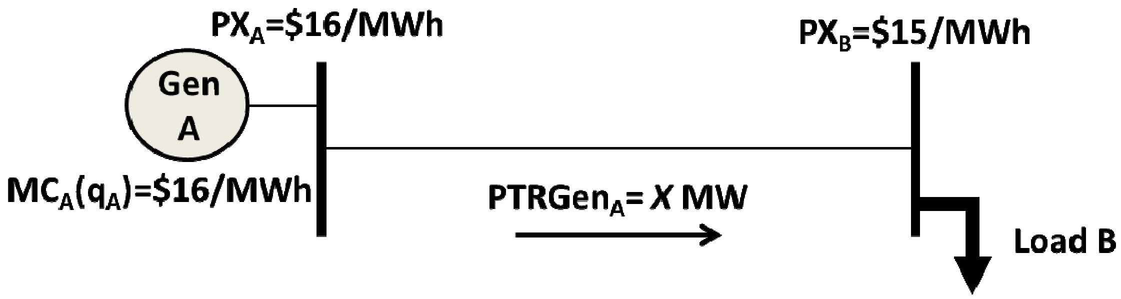
- The capacity released in the intra-day auction is the sum of unused and/or unsold day-ahead capacity units and the extra capacity that is made available through netting of the already submitted day-ahead nominations.

To maintain system security if a capacity shortage occurs, the operators of IFA can curtail interconnector capacity and associated physical nominations as they see fit. In such a case, capacity is curtailed pro-rata for all unit holders in the following priority order: intra-day units, day-ahead units, long-term units. Affected unit holders are paid back the initial purchase price of the curtailed units. In addition, a *force majeure* clause is included in the IFA access rules, stating that under exceptional situations the Operators cannot be held responsible to pay any compensation to the users. Market participants take these into account and the value they bid accounts for this reduced firmness of capacity rights. This issue is further explored in Section 3.8.

3.2.4 Worked Example of Cross-border Bilateral Trading with PTRs

In the case of explicit auctions, holders of physical transmission rights decide for themselves the amount of energy to **nominate** for transmission over the interconnector **before knowing the area prices and the resulting value of their rights.** This implies that there might be circumstances where a market participant has nominated his transmission rights and has produced or purchased power in his local exchange only to find out that the prices in the importing region are lower than his local prices. To illustrate this point, consider the following worked example as a 2 bus-bar system resembling IFA with the subsequent day-ahead prices.

Figure 3.1: Schematic of worked example for PTR system



Assuming the Generator in area A ("Gen A"), with a marginal cost of €16/MWh has nominated, before the day-ahead explicit or implicit auction, *X* MW to serve their bilateral contract with Load B with a strike price at €20/MWh. In this case Gen A would be making a profit of €4/MWh. Given that area price A is €16/MWh and the area price B is €15/MWh the generator could instead not produce anything (or sell to the local exchange)[30] and not nominate their PTRs and serve the contract by purchasing power in the area B power exchange thus making a profit of €5/MWh. This implies that there is a welfare loss of €1/MWh if the rights are nominated, since Gen A is producing power which could be produced by a cheaper generator in area B.

[30] *The generator would be indifferent between selling or not producing in their local PX given that the local PX price is equal to Gen A marginal cost.*

Consider now the case where the price differential is reversed i.e. the price in area A is $15/MWh and the price in area B is €16/MWh. If Gen A nominated their rights than Gen A would still be making a profit of €5/MWh by serving their bilateral contract by buying the energy from the local Px rather than producing it. If however, Gen A did not nominate their rights before day ahead than Gen A would receive €1/MWh under the UIOSI regime (area price differential) and buy the energy from the PX in area A at €16/MWh. This would imply that he would still be making a profit of €5/MWh.

It can be easily seen that whenever the price in area B is greater than the price in area A, than Gen A would be indifferent between nominating their PTRs or not nominating. But this is not the case when area B is less expensive than area A. Since nomination needs to take place before the day ahead coupling (or explicit auctions), nominating the rights carries the risk of inefficient dispatch and foregone profits.

The above example illustrates two facts about the cross-border trading under the PTR with UIOSI:

- Since, at least in the case of IFA, the PTR owner is required to nominate their PTR before the day ahead auction, this can lead to welfare loss, given the lack of information on day ahead prices at the time of nomination
- With sufficient liquidity in the local PXs, from a generators/traders point of view, it is always advantageous not to nominate the PTRs

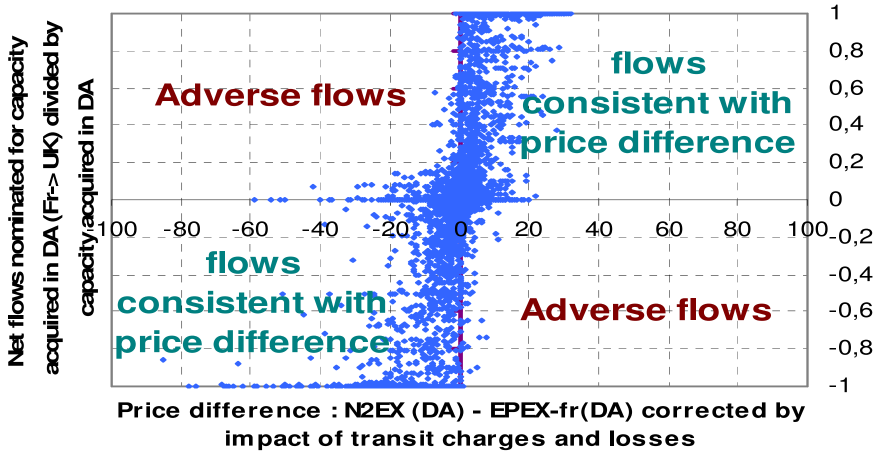
Nonetheless, the above conclusions are contingent on certain assumptions; that there is high liquidity in the PXs, imbalance prices are efficient and equal to PX clearing prices and that PX participation fees are not significant. Given the Target Model aspirations of market coupling with implicit auctions, PX liquidity in such an environment can be taken for granted. On the other hand, PX fees can be an issue especially for smaller market participants, and this has been flagged by some traders.

There have been several occasions on the IFA where adverse flows are observed, meaning that power flow was from the high-price area to the low-price area. For example, for the period January to June 2010, 13.7% of transmitted energy volume was from a high-price to a low-price area[31] due to wrong nomination of transmission rights – see Figure 3.2. This is clear evidence that the mechanism for trading rights on the interconnector does not assure efficiency.[32]

[31] *National Grid, RTE, ELIA, TENNET, 2010, "Joint Proposal for a Day Ahead Market Coupling Initiative between GB and Mainland".*

[32] *RTE, 2010, "Response to Ofgem's Electricity Interconnector Policy"*

Figure 3.2: Adverse flows on IFA for January 13th to June 30th 2010



Source: National Grid, RTE, ELIA and TENNET, "Joint Proposal for a Day Ahead Market Coupling Initiative between GB and Mainland", September 2010.

3.2.5 Cross-border Bilateral Trading with FTRs

In this section, we need to distinguish between FTRs as options and FTRs as obligations. Where rights are constructed as FTR options, bilateral trading can be carried out in the same manner as PTRs with UIOSI, but with the "sell it" provision being mandatory. This implies that market participants would not nominate any of their rights and trade all their volumes through the PXs.[33]

When rights are constructed as FTR obligations, trading would be the same as FTR options but with the potential of a negative payout when area price differentials in the direction of the FTR (sink – source) become negative. Although this might seem as an extra layer of risk for FTR obligation holders compared with FTR options or PTRs with UIOSI, as shown in Section 3.3, this is not necessarily the case. FTR obligation rights allow TSOs to auction off (in long-term auctions) significantly higher volumes of transmission rights through flow netting. This is highly beneficial for the efficiency of the use of the link and promoting competition between generators either side of the link. This is also explored in detail in Section 3.3.

Furthermore, since FTR are financially settled without the need of nomination, the volume released for day-ahead market coupling will be equal to the computed NTC rather than the ATC (= NTC – Nominated Rights) as is the case for PTRs.

FTRs, whether options or obligations, have a distinct advantage over PTRs due to their inherent definition as point-to-point (price zone to price zone) instruments, regardless of the network topology by which those points are connected, in comparison to PTRs that are defined strictly over a specific interconnection.[34] This becomes a primary concern when

[33] In reality, this is not necessarily the case as bilateral trading without PX participation can still take place. For example, in the US LMP pools market participants can nominate self-scheduled trades which are automatically accepted by the pool clearing algorithm. Then market participants pay an access charge equal to the LMP differential between their nominated sinks and sources, which can claim back if they hold the equivalent FTRs. Consequently, these market participants are not exposed to any liquidity risks or PX fees of their nodal exchanges (which in fact do not exist for all nodes).

[34] There are suggestions that PTRs can also be defined as point-to-point (PTP). Although this is possible it is not very clear how it would work in practice. Assume, for example that a trader nominates a PTP PTR between England and Italy.

looking at the European grid as an integrated system, where market participants would be willing to trade electricity between non-neighbouring countries. This could be possible but more complex to achieve in practice with PTRs since in some cases users would have to buy PTRs over many different interconnectors to cover the desired contract path. A system with FTRs would be potentially more transparent, because a market participant could hedge his position more easily if they decide to trade between any two countries by simply acquiring the associated FTRs. This is an issue, which has been analysed extensively in the early days of the nodal market design as the FTR/FGR (FlowGate Right) debate, with the FTRs emerging as the preferred option. The main conclusions are presented in the next section.

3.2.6 Financial Transmission Rights and Flowgate Rights

Flowgate rights (FGRs) are TRs defined over a specific transmission line or "flowgate" rather than point-to-point. Under the point-to-point design of standard PTRs and FTRs, someone sending electricity from zone 1 to zone 2 is only required to buy a right from zone 1 to zone 2, as if the connection between zone 1 and zone 2 had a well-defined capacity, related to the direct line or lines connecting the two zones. In reality, electricity flows are affected on all indirect routes also, and the FGR concept is to require the user to buy a bundle of rights reflecting the impact they have on all the indirect routes too.

There have been a number of market design proposals[35,36] for FGRs with different characteristics and definitions. In particular, FGRs can have a physical interpretation such as PTRs, purely financial such as FTRs and can be defined as either options or obligations.

Physical FGRs suffer from similar criticisms to PTRs and in fact under flow-based market coupling (FBMC) they should be equivalent. Similarly, assuming a fixed system topology financial FGRs and FTRs are also equivalent since FTRs are linear combinations[37] of FGRs.

In effect, financial FGRs give the right (and obligation if defined as two sided obligations) to their holder to collect the congestion surplus created by a particular flowgate.[38] In order for a market participant to fully hedge its congestion exposure for a particular trade between two areas they would need to acquire FGRs for all the interconnectors that this particular trade creates power flows over, as defined by the Power Transfer Distribution Factor (PTDF) matrix of the system.[39] This is exactly equivalent to buying a single FTR between source and

This implies that the NTC for all the interconnectors affected by the injection from England to Italy would need to be reduced according to the Power Transfer Distribution Factors (PTDF) (see definition at footnote 35) of the common grid model, which might not be so straightforward. Overall, defining PTRs as PTP would make them almost equivalent to FTR options with the exception of mandatory nomination, which has been shown to have the potential to lead to inefficiencies.

[35] *California ISO, "Congestion Management Reform Recommendation," July 11, 2000.*

[36] *Tabors Caramanis & Associates, "Real Flow A Preliminary Proposal for a Flow-based Congestion Management System," Cambridge, MA, July 18, 2000*

[37] *The co-efficients of the linear combination are equal to the PTDF matrix coefficients of the system – see definition at footnote 35.*

[38] *The congestion surplus in this case is computed by the amount of FGRs (MW) times the flowgate multiplier, which corresponds to Langrangian multiplier of the inequality constraint of the particular critical branch. For more information refer to Chao et al 2000.*

[39] *The PTDF matrix has a row for each transmission link (rows) and a column for each node. It is defined in relation to a chosen reference node – the column for that reference node will be zero in every row. The PTDF for a transmission link in relation to a specific node is the amount by which the load on that transmission link changes when a unit injection is made at that node, and withdrawn at the reference node. See "Financial Transmission Rights: General Principles and*

sink, hence the equivalence of the two sets of TRs. Moreover, the inefficiencies associated with zonal approximations would still be present in a market design with FGRs since NTC's for the particular flowgates would need to be computed in a similar manner.

Since FGRs are defined for single interconnectors, the theoretical advantage of these TRs over FTRs is that FGRs can be auctioned on a flowgate by flowgate basis and secondary trading can be facilitated in a decentralised manner which is considered as a major advantage over FTRs. Although the FTR formulation allows for some decentralised trading and reconfiguration of the individual rights, this decentralised trading would be limited to rearrangement of the parts without changing the aggregate pattern of inputs and outputs as changing the aggregate patterns of FTRs requires co-ordinated auctions.

However, the importance in the difference in access market design is an empirical question and a successful implementation of FGRs depends upon a number of practical considerations being satisfied:

- That there are sufficiently few flowgates or constraints for a practical implementation
- Known and fixed capacity limits at the flowgates
- Known and fixed power transfer distribution factors that decompose a transaction into the flows over the flowgates

At the initial design stages of the PJM market, a study on a potential FGR system in the area identified 28 constrained significant flowgates (CSFs). However, in real time and for a 6 month period the actual number of CSFs was 43, and none were included in the above list. In a 2 year period the list had grown to 161 CSFs, which would imply that each single point-to-point transaction would require 161 FGRs in order to provide full hedging. This demonstrates not only the fact that there might be a large number of CSFs, but also the difficulty in identifying these in advance.

A successful implantation of FGRs requires stable PTDFs, since changing these would imply that market participants would need to constantly monitor and reconfigure their FGR portfolio. However, outages of network circuits and application of network control devices will often change the PTDF matrix. In case of FTRs this might lead (but not necessarily) to revenue inadequacy for the TSOs and, depending on the firmness definition, to incomplete hedging for market participants. In case of FGRs, this would further require that market participants re-configure their FGR portfolio to match the new PTDFs, adding an extra layer of complexity and uncertainty. Furthermore, given the similarly of FGRs to PTRs defined over physical flowgates (rather than point-to-point), it is difficult to envisage a set of FGRs that could hedge the price risk between a zonal/nodal price and a reference price (SMP) in the same way that FTRs can. For these reasons FTRs have been preferred market design options and FGRs have not yet been successfully implemented in practice.

In the case of the Single European Electricity Market, where FTRs would be defined between large zones rather than nodes, decentralised secondary trading of the rights has the potential

the Texas Experience", Shmuel S. Oren, University of California at Berkeley, Presented at the project workshop in London,31 May, 2011.

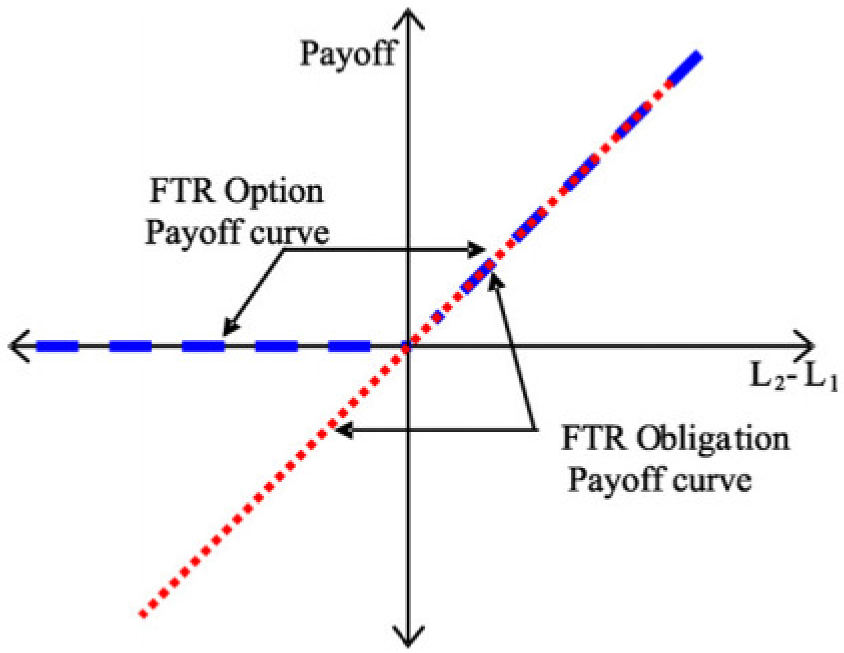
to be significantly more liquid than in nodal markets. Therefore, the key benefit of an FGR scheme (facilitate decentralised trading of TRs) will not be as profound, whereas all the disadvantages would remain.

3.3 Transmission Right Options and obligations

3.3.1 General Features of FTR Options and Obligations

As described in the previous section, the payout of the FTR is the price differential between the sink and source times the FTR volume (MW). In the case of the FTR options if the sink-source price differential is negative then the FTR payout is zero. On the other hand, FTR obligations can either have a negative or positive payout depending on the area price difference and the directional definition of the FTR. This is illustrated in Figure 3.3.

Figure 3.3: Payoff Curves for FTRs as Options or Obligations against Price Differential



If market coupling and an implicit auction is in place **for a single interconnector,** then the payout (other things equal) of a PTR with UIOSI is equivalent to the payout of an FTR constructed as an option, both for the traders and the TSOs. But there are significant differences when FTRs are constructed as obligations.

It can be demonstrated that auctioning of FTR obligations is equivalent to a virtual energy auction or market dispatch. This implies that by taking into consideration the physical limitations of the system and FTR bids/offers, one can auction all the capacity of the system by taking into account the counter-flows. This is called the Simultaneous Feasibility Test (SFT). On the other hand, the security constrained economic dispatch formulation (which should be equivalent to the day ahead flow based market coupling) does not include options ,since in the real dispatch everything is an obligation. Consequently, the auction problem for

FTR options does not follow the formulation of economic dispatch and hence a number of TSOs do not issue FTR options. According to Hogan:[40]

> "The analytical problem for options is similar to the problem for physical rights. Without knowing all the other flows on the system, it is not possible in general to know if any particular transaction will be feasible. Hence, to guarantee feasibility it is necessary to consider all possible combinations of the exercise of options. For example, if too few of the other options are exercised, there may be insufficient counterflow to support a particular transaction; or if all the options are exercised, some other constraint might be limiting. This ambiguity does not arise with obligations, which by definition are always exercised."

Another drawback of FTR options is that they are not decomposable in the sense of to and from a hub. For example, an FTR option from bus 1 to bus 2 cannot be decomposed into two FTR options from 1 to a Hub and the Hub to 2. The total payment under the two options would be $\max(0, P_2 - P_{\text{hub}}) + \max(0, P_{\text{hub}} - P_1) \neq \max(0, P_2 - P_1)$. FTR obligations can be decomposed to any chain of FTRs that leads from the initial source and final sink are the same. This is a disadvantage of FTR options since hubs defined for FTR trading increase liquidity (Trainen and Papalexopoulos[41]) leading to better price discovery and efficiency.

Thus FTR obligations facilitate a wider range of congestion risks that can be hedged, and greater willingness of market participants to hedge, than FTR options or PTRs with UIOSI. This is because the possible auctioned volume and definitions of FTR options will always be a subset of the possible auctioned volume and definitions of FTR obligations.

On the other hand, assuming that auctions for both FTR options and obligations meet the SFT, then revenue adequacy for the TSO is guaranteed as long as the system topology does not change. Consequently, the TSO needs to manage the same risks related to transmission capacity availability under both definitions.

Nonetheless, the FTR obligations create a credit risk for the TSO that is not present with FTR options or UIOSI PTRs. When matched with a corresponding delivery of power, the charge for transmission usage in the form of price differentials just balances the FTR payment, and there is a perfect hedge. This is true whether or not the price difference is positive or negative. If the price difference is negative, the schedule provides valuable counterflow for which the provider is paid, and the payment from the spot market dispatch just balances the obligation under the FTR and vice versa. Consequently, for market participants looking to hedge their physical positions, the potential negative payouts should not create more risk. But, as is the case with the FTR options, speculators can and should be offered the right to participate in the auctions for transmission rights. Given that the payout of an FTR obligation might be negative, these market participants might become insolvent. This in turn, might not allow the TSO to honour other FTR payments leading to revenue inadequacy. This can be resolved through a clearing house.

When there are market participants with market power, the detailed market structure can serve either to increase or to diminish their exercise of market power. There has been extensive literature concerning the relationship between market power and transmission rights. It has been been shown that under certain conditions FTRs increase market power

[40] *W.Hogan (2002), "Financial Transmission Rights Formulations", Center for Business and Government, JFK School of Government, Harvard University, available: http://www.whogan.com.*

[41] *R. Treinen and A. Papalexopoulos, (2003) ECCO International, "Important Practical Considerations in Designing an FTR Market," IEEE Power Engineering Society Summer Meeting.*

(Joskow and Tirole,[42] Bushnell[43]) whereas in other circumstances they reduce it (Stoft[44]). In particular, when traders cannot arbitrage price differences across markets by buying FTRs, market power may be enhanced, for example if an importing generator has significant market power in the import market. This is one reason why regulators may limit the amount of import capacity that incumbent generators can hold. Whereas both FTR options and obligations can result in any increase in generator market power when the generator is located in the sink, only FTR obligations can lead to a reduction in market power when generators located in the source hold the FTRs (Young et al[45]). Gilbert, Neuhoff and Newbery[46] showed that in efficiently arbitraged uniform-price auctions, generators will only obtain contracts that mitigate their market power. The reason is simple – the incumbent will only earn the domestic marginal revenue from using the PTRs, while the traders will receive the full local market price, and that will necessarily exceed the marginal revenue if there is any market power to be exercised. Contracts inherited or bought in a "pay-as-bid" auction can, in contrast, enhance market power. Coupled markets are uniform price auctions and thus the Target Model would seem to allay fears about increased market power.

3.3.2 FTR Options and Obligations in US Markets

All US markets that operate under Locational Market Pricing (LMP) market arrangements offer FTR obligations, and some of them offer both options and obligations (PJM Interconnection and CAISO, the independent system operator in California). Many Independent System Operators (ISOs) in the USA, such as Midwest ISO, New York ISO and New England ISO issue FTR obligations in their annual and monthly FTR auctions and have been exploring the possibility of issuing FTR options for a few years. Their reluctance to issue and administer an FTR option market underscores the challenges involved in designing a set of options while ensuring revenue adequacy. Furthermore, the lack of availability of adequate frameworks, models or methods to price these options raises serious concerns about the liquidity of secondary markets.

In markets that do offer FTR options such as PJM, these are only offered for annual or monthly auctions and not in longer-term auctions, reflecting their reluctance to commit significant capacity for options offerings. Importantly, the market demand for options has been very low and market participants have indicated that there are satisfied with the FTR obligation offerings.

In summary, the practical experience from the US markets is that FTR obligations are the main instrument for hedging congestions costs and FTR options act as a complementary instrument offered in only three markets and for limited durations. This is in stark contrast with the present philosophy of the Target Model which favours FTR options over obligations, and suggests that both products should not be offered over the same interconnector.

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[42] *Joskow, P. and J. Tirole (2000). "Transmission Rights and Market Power on Electric Power Networks," RAND Journal of Economics, 31: 450-487.*

[43] *Bushnell, J. (1999). "Transmission Rights and Market Power," The Electricity Journal, 77-85.*

[44] *Stoft, S. (1999) "Financial Transmission Rights Meet Cournot: How TCCs Curb Market Power," The Energy Journal, 0: 1–23*

[45] *Joung M., Baldick R. and You Seok Son, (2008), "The Competitive Effects of Ownership of Financial Transmission Rights in a Deregulated Electricity Industry," The Energy Journal, International Association for Energy Economics, vol. 29(2), pages 165-184.*

[46] *Gilbert, R.J., K. Neuhoff and D.M. Newbery (2004) 'Mediating market power in electricity networks', Rand Journal of Economics, 35 (4) Winter 691-711*

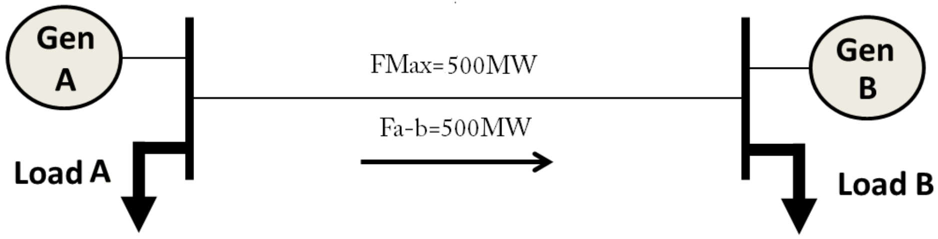
The obvious solution to the claim that options are desirable is to assume that TSOs will primarily sell obligations and that traders or financial institutions can issue options, possibly hedging these (to some extent) by buying obligations and/or local CfDs – if the demand is there and the risk appetite of institutions and traders is adequate then the market will emerge, if not it will confirm the suspicion that the value of options is less than the risk costs they bear.

3.3.3 Options, Obligations and Netting

The most important advantage of TR obligations vs options (whether financial or physical) is the two sided nature of obligations, which can facilitate netting of TRs and potentially increasing the volume of auctioned rights, when market participants are looking to hedge the congestion price risk of their energy contracts.

This can be easily illustrated in the following 2 bus bar example illustrated at Figure 3.4:

Figure 3.4: Two Bus Bar example



Assume that Gen A has a contract for 1000MW with Load B and equivalently Gen B has a contract with Load A for 500MW.[47] The ATC of the interconnector is 500MW in both directions. Assuming that the optimum dispatch corresponds to the contractual positions of the two generators i.e. Gen A produces 1000MW and Gen B produces 500MW to meet an aggregate demand of 1500MW (Load A is 500MW and Load B is 1000MW). The resulting 500MW interconnector power flow does not violate the ATC limitation since the injections and withdrawals of the market participants are ***netted***. Consider the following three market designs, PTRs, FTR options, and FTR obligations:

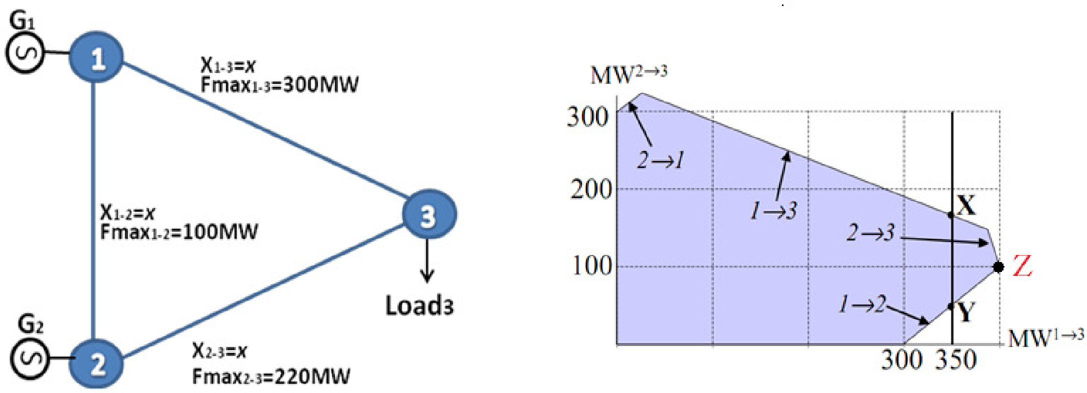
- PTRs: The energy contract between Gen A and Load B could not be supported, since that the maximum volume of PTRs that could be made available to facilitate the cross-border trade would be limited to the directional physical capacity of the link, which is 500MW. For Gen A to facilitate such a contract then it would need to enter into a physical swap with Gen B, with associated transaction and search costs.
- FTR Options: Gen A could underwrite the contract with Load B and purchase a maximum of 500MW FTR options to hedge its congestion risk. For the remaining volume Gen A would need to buy a counter-flow CfD (option or obligation) from Gen B for 500MW, with the associated transaction and search costs.
- FTR Obligations: The market participants would be able to buy directly from the FTR auction TRs that match exactly their contractual agreements. This is possible

[47] There are a number of reasons why such a set of contracts might arise in electricity markets. These might include environmental reasons (buying from low carbon generators), commercial and competition reasons among others.

since their bids in the TR auction would be netted and a maximum volume of long term transmission rights would be offered, which is in line with the objective to facilitate cross-border trades through appropriate long term TRs.

But the availability of FTR obligations does not preclude also making FTR options available. Indeed we would describe it as desirable to offer both, since that allows market participants to make their individual commercial choices. In this 2 bus-bar example hedging through a combination of FTR options and CfDs might be trivial, but in meshed systems (such as the envisaged Common Grid model) this might not be so straightforward as the following 3 bus-bar example (Figure 3.5) illustrates.

Figure 3.5: Three Bus Bar example



In this example generators at nodes 1 and 2 are competing to meet loads (net of local generation) at node 3, and there are flow limits on each of the three lines. The interesting situations in this example arise when there is sufficient low-cost generation at Node 1 that more than 300 MW of transactions from node 1 to node 3 would be economic, which would be in excess of the 300MW line capacity from 1 to 3. The "nomogram" graph shows which combinations of 1->3 and 2->3 transactions are feasible, given the flow limits stated, and assuming all lines have the same impedance. The nomogram also indicates which flow constraint is binding on each face of the nomogram. We see that the binding constraint is frequently the 100 MW limit on the flow from Node 1 to Node 2, preventing as much as 300MW from flowing from Node 1 to Node 3, albeit that in other configurations more than 300MW can flow. This nomogram illustrates the fact that no more than 300 MW can flow from node 1 to node 3 without violating the 1-to-2 constraint unless there is some generation at 2 to produce some 2-1 counterflow.

Assume that the economic dispatch corresponds to the point Z (which does not violate any NTC constraints due to netting of injections), which implies that G2 produces 100MW and G1 produces 400MW and that Load3 has entered long term energy contracts to secure this supply. Once again consider the hedging options of the market participants under different TR market designs, FTR Options and FTR Obligations.

- FTR Options: G1 would be able to only hedge 300MW of their 1->3 transactions. In order to be fully hedge it would need to buy another 100MW of CfD 1->3. These CfDs (once again options or obligation) could be constructed and offered by a third party, but in this case this is not so straightforward as in the 2 bus-bar example. In fact this would involve G1 buying and G2 offering 50MW of OTC flowgate rights (assuming that such a secondary markets for flowgate rights exists) for interconnector 1->2.

- FTR Obligations: G1 and G2 could simultaneously fully hedge their congestion risks by acquiring FTRs matching their energy contracts from the TR auction. This would be possible due to the netting of their bids through the Simultaneous Feasibility Test.

Clearly, the three bus-bar example illustrates that through netting of FTR obligations the volume of allocated long term transmission rights can significantly increase.

3.4 VOLUME OF ALLOCATED RIGHTS AND CAPACITY CALCULATION METHODOLOGIES

3.4.1 Introduction

The primary objective as outlined in ACER's consultation draft *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity* (FG, 11 April 2011) is to ensure the optimal use of the transmission network capacity in a coordinated way. The draft FG states that the Network Code to be published by ENTSO-E shall define and implement either a Flow-Based method or an Available Transfer Capacity (ATC) method. The FG explicitly states that a Flow-Based method is seen as overall more efficient, especially for allocating capacity in the short-term and in highly meshed systems such as Central West Europe. Co-ordinated ATC is described as an acceptable method for short-term capacity calculations in less meshed networks. The FG recognises the possibility for the coexistence of different calculation and allocation methods even within the same zone and note that the presented solution should take all possible adverse effects into account.

In this section we will examine four capacity allocation methodologies and the potential volume of allocated rights under each methodology, these being:

- Explicit Auctions of PTRs
- Locational Marginal Pricing
- Market Splitting
- Flow Based Market Coupling

3.4.2 Explicit Auctions of PTRs

Currently, the majority of cross-border interconnectors in Europe use the concept of PTRs. These rights give the right to the holder to transfer electricity over an interconnector over a time period in a specified direction. In most cases PTRs are sold in explicit capacity auctions, meaning that interconnector capacity is auctioned separately and independently from where electricity is auctioned. The capacity rights are usually released in several auctions organised throughout the year. These auctions are organised by the participating TSOs. The timeframes are:

- Long-term auctions. These are held periodically throughout the year, in many cases several months before time of delivery. Participants can bid to purchase rights covering a long time duration such as a calendar year or month.
- Day-ahead auctions. These auctions are held one day before delivery.
- Intra-day auctions. These allow participants to further optimise their position according to the latest information (e.g. available wind generation levels).

The amount of PTRs to be released in long-term auctions is in most cases predetermined. For instance, the TSO could organise various long-term auctions where 90% of capacity is sold, reserving the remaining 10% of capacity to be released in the day-ahead auction. Typically, unsold rights cascade to future auctions.

The essence of a long-term PTR is that it includes the right to nominate, and prior to exercise of that right, PTRs are options. PTRs must be nominated within a specified period before a defined gate closure. PTRs sold short term, typically day-ahead, are considered to be already nominated. Once nominated, PTRs become obligations, meaning that the participant will have to deliver the energy or otherwise deemed to be out-of-balance and subject to associated penalties. Once gate closure occurs for long-term PTRs, the TSO is able to calculate through netting the Available Transfer Capacity (ATC) left over the interconnector. Subsequently, the TSO publishes the ATC calculation and initiates the day-ahead auction. The procedure is similar for the intra-day auction. In summary, the amount of capacity to be released in each auction is calculated in the following way:

- The amount of capacity released in long-term auctions is typically fixed and does not take into account netting.
- The amount of capacity released in the day-ahead auction is again fixed but the TSOs also include any unsold/unused long-term units and any extra capacity that can be made available through the netting of already submitted long-term nominations.
- The capacity released in the intra-day auction is the sum of unused and unsold day-ahead capacity units and the extra capacity that is made available through netting of the already submitted day-ahead and long-term nominations.

The amount of capacity to be released in these capacity auctions is determined by the TSOs. Moving closer to the time of delivery, there are several effects and constraints that need to be taken into account by the TSOs when calculating ATC values. The task of identifying the optimal amount of capacity to release can be very complex for a variety of reasons:

- In meshed systems, TSOs have to take into account flows within their own and neighbouring national/regional electricity systems and the associated loop flows arising over the interconnector. It is not possible to consider cross-border links in isolation, unless the interconnector in question is a single controllable high voltage DC link.
- There is a possibility that market participants that have agreed to transmit electricity over an interconnector might fail to do so. For example, consider a 1,000 MW interconnection between countries A and B. It is possible to nominate 2,000 MW from A to B and 1,000 MW from B to A, since the effective flow on the interconnector is 1,000 MW from A to B and thus within the security limits. But if the generators in B failed to deliver, we would automatically find the resulting flow in violation of the line's limit. However, this situation could be resolved by purchasing shortfall of power in area B through the balancing market, and charging the generator that failed to deliver for replaced power. In theory this should happen automatically, as each country's TSO will be required to balance supply and demand within their dispatch area, subject to interconnector constraints. If generators in B failed to deliver, then A's exporting generator would, as before, physically deliver 1,000 MW to demand in A and 1,000 MW over the interconnector, while the TSO in B will find its local exporter in

imbalance and have to act to correct that problem, in the process automatically balancing flows over the interconnector (subject to the standard problem that the ATC may have been affected by a change in the pattern of injections in B). The risk of non-delivery is often argued to be a reason for releasing network capacity in a conservative manner to prevent exposure to risks of non-delivery by market participants. A more mature approach would be to consider the actual delivery risk from the range of sources, and the availability and level of balancing needed to respond to that risk. An external source offering to supply to the market could in fact increase the local supply of balancing services, or, through diversity, reduce the overall non-supply risk.

- In cases where a country is interconnected with neighbouring states via numerous links, e.g., as in the case of highly meshed system in Central Western Europe (CWE), the TSO has to decide how to "split" ATC over the different interconnectors. For example, a TSO might have to choose between two seemingly equivalent solutions: (i) release 500 MW on the A to B interconnector and 300 MW on the A to C interconnector (ii) release 300 MW on the A to B interconnector and 500 MW on the A to C interconnector. This decision might look equivalent in volume terms, but it is not in economic terms. How much market participants actually value access to each of the interconnectors becomes known only after the clearing of the energy auctions, which takes place after the PTRs have been allocated. Secondary markets where PTRs can be traded can allow participants to optimise their position. But the explicit auctioning of PTRs has an inherent inefficiency since the TSO is required to make a decision on an important binding constraint (ATC value calculation) ignoring the views of the energy market.

The traditional approach to these issues is a conservative stance and the use of heuristics and past experience to predict the likely behaviour of the system. This is standard practice, especially in systems that are less meshed (such as the Nordic system), and thus allow for more straightforward analysis approaches. However, with increasing volumes of unpredictable (until a day ahead) wind, these heuristics are likely to become less informative. One important component that is essential in calculating ATC values more efficiently is sharing of information between TSOs. Sharing of data such as expected flows in neighbouring lines and demand forecasts can help each TSO take a more informed decision.

The effects of each TSO's decisions on neighbouring systems have to be taken into account. This can sometimes prove to be difficult due to various reasons, such as discrepancies in the way TSOs model their systems. If nominations all have to specify the point of injection and if all that information is provided to a central location, then the flows across each interconnector can be more accurately predicted, and hence more capacity released into the intra-day markets. This is widely understood by European TSOs and we have already seen efforts to standardise and organise this coordination effort.

In the past years we have seen the creation of two regional capacity auction offices, CAO (CAO Central Allocation Office Gmbh) and CASC (CASC.EU S.A.), dedicated to facilitate this process.

- CAO is the auction office for the Central Eastern European region and is responsible for allocation and management of transmission capacity over 9 interconnectors among 8 TSOs. The countries participating in CAO are Germany, Hungary, Poland, Slovenia, Slovakia, Austria and Czech Republic.

- CASC is an auction office that facilitates the coordination of 12 TSOs, managing capacity allocation over 14 borders. The countries participating in CASC are Netherlands, Belgium, France, Italy, Greece, Slovenia, Austria, Switzerland, Germany and Luxemburg.
- These auction offices are responsible for the coordination of long-term NTC capacity calculations, organising the long-term and daily explicit auction process and the secondary market. The auction offices have developed their own grid models enabling them to capture the characteristics and constraints of each system. By using a sophisticated algorithm and pooling all available information, they allocate capacity across the different boundaries while taking into account the induced loop flows. The auction offices are also responsible for the settlement of payments, essentially acting as the primary interface between regional TSOs and market participants.

As mentioned earlier, explicit auctioning of PTRs is well established and documented practice in European markets. But one major disadvantage of explicit PTR auctions is that they do not allow traders to arbitrage efficiently between the interconnected countries in the long term and day-ahead timeframe, because traders have to take a decision to nominate their long-term rights before the operation of the day-ahead market. Without knowledge of the closing price in the day-ahead energy auctions they cannot make a fully informed decision. As a result, in many cases, we see cases of traders misjudging and nominating rights that they hold in the "wrong direction", as described in section 3.2. This could potential be resolved by declaring all, rather than only residual, network capacity available for day ahead market and settling the right financially.

3.4.3 Locational Marginal Pricing

In Locational Marginal Pricing (LMP) markets, there is potentially a different price at each network node and in each time period, reflecting the temporal and locational variation of the energy price related to demand. This method aims to represent the electricity system by taking into account various economic and technical characteristics, such as line flow limits. Generators and load do not explicitly participate in a capacity auction. Rather, LMP is a fully coordinated implicit auction, where capacity is implicitly allocated through bids for consumption and generation at each node. The ISO collects bid data and then clears the market by maximising social welfare, subject to network constraints. When no congestion exists in the network within a region, the electricity price is equal for all nodes in that region. In the event of congestion, electricity prices can vary from node to node. These price differentials give rise to a congestion surplus collected by the ISO.

The fact that every single node can have a different price means that congestion risk becomes a primary concern in LMP markets. The way to hedge this risk in these markets is by purchasing FTRs. FTRs are sold in auctions organised by the ISO throughout the year. ISOs calculate the volume of FTRs to be released for purchase in auctions by using the Simultaneous Feasibility Test (SFT). The SFT guarantees that if all the outstanding FTRs are exercised simultaneously to support physical transfers between their corresponding sources and sinks, then all these transactions can be supported by the physical grid, i.e., no transmission constraint will be violated providing the original topology is maintained.

In each calculation that awards FTRs, it is important to test that the resulting flows are within network capacity. ISOs do this by representing all the FTRs simultaneously in the network model, together with any loop flows from the external network. The network flows are solved for in both the pre- and post-contingency states and checked for limit violations. Assuming perfect knowledge of the expected locational marginal prices for energy in an electricity grid and all bidders being rational and risk-neutral price takers, the FTR auction problem is equivalent to the virtual energy auction problem. The objective of the optimisation is to maximise auction revenue, thus allocating FTRs to the market participants that value them high, subject to feasibility of all resulting flows once exercised.

3.4.4 Market Splitting

In theory market splitting is similar to LMP in the sense that there are different electricity prices for different areas in the system. But in contrast to LMP where there could be a different price for every node, the market splitting arrangement aggregates groups of nodes into zones. Typically market splitting is applied when there are several regions each with a different TSO (in the EU, this region is typically, but not necessarily, a country) but the area of each TSO may be divided into several price zones between which there is significant congestion but within which the cost of managing congestion is low. The task of defining the zones is the responsibility of the regional TSO. Usually the zones remain fixed for an extended period. Zonal definition has also changed in response to regulatory involvement, and may also need to change if the need arises from changes in locational patterns of demand and generation or new transmission investments.

The optimisation method for Market Splitting is similar to that of an LMP market, based on the Security Constrained Optimal Power Flow (SC-OPF), with the addition of two extra constraints to equalise nodal prices within the zone (Krause[48]). When the system is uncongested, all the zones have the same price, whereas when the system is congested, different areas have different prices.

The market set-up involves a common central power exchange (PX). Market splitting revolves around the day-ahead market. Market participants have to submit bids and offers to the common Power Exchange in order to trade energy across zone borders. Capacity is allocated implicitly according to the bids/offers of market participants in the respective zones and by the central PX maximising arbitrage trade. TSOs cooperate to calculate the day-ahead ATC values across all links in the system and pass this information to the Power Exchange. It is important to note that bilateral contracting between parties within the same zone can take place without participating in the PX. Consequently, interzonal flows need to be quantified and netted off when estimating ATC values. This is usually done using heuristic methods such as recent dispatch schedules. In radial systems, where flows can be fairly predictable, this is usually a straightforward task. But the effect of loop flows due to interzonal nominations becomes more prominent in highly meshed systems, where ATC calculation can often prove a complex task. Increasing shares of intermittent wind are likely to make past heuristics less reliable, and may justify dedicated weather forecasting for short-range power flow predictions to improve ATC estimates.

At auction closure, bid/offer data and ATC values are input in the market splitting optimisation algorithm. When a potential solution to clear the auction is identified, it is checked for flow feasibility. No simplifications to the electricity network are made and both intrazonal and interzonal flows are calculated and checked against the pre-determined ATC values. In case of ATC violations, imports and exports between zones have to be re-adjusted in the most economically efficient way to relieve congestion. The optimisation process stops

[48] *Krause, T (2007) 'Evaluating congestion management schemes in liberalized electricity markets applying agent-based computational economics', Swiss Federal Institute of Technology Zurich, 53-54.*

once the solution that maximises arbitrage trade while respecting flow limits is identified. Consequently, market participants must dispatch their units according to the auction outcome or pay imbalance charges.

Market splitting has many distinct advantages as a method of capacity allocation. The fact that energy and capacity auctions take place simultaneously means that capacity allocation maximises social welfare. In addition, there is little room for adverse flows since the system only allows flows from low-price to high-price areas.

Overall, market splitting is deemed as a successful way of allocating capacity in the markets it has been applied, mainly Nord Pool. One important advantage is that it precisely represents the technical characteristics of the system, capturing all important system constraints and thus allowing the system to operate closer to its capacity limits. In addition, it is a transparent procedure since the market is cleared through a predefined publicly available algorithm.

3.4.5 Flow-Based Market Coupling

Flow-Based Market Coupling (FBMC) is an evolution of the concept of zonal pricing present in market splitting. It involves implicit auctions and allocates capacity by solving an optimisation problem of security-constrained economic dispatch. But it models the electricity system in a more simplified way than market splitting or LMP. The main differences are listed below:

- Market splitting views the system as an integrated whole that is "split" between different price zones when cross-border congestion occurs. Conversely, Flow-Based Market Coupling sees the system as an aggregation of inherently "split" independent markets. This could be regarded as a practical advantage over other systems; in the sense that it can be implemented without a major restructuring of the way PXs currently operate in Europe.
- In market splitting, there is one single PX that is responsible for co-ordination of the day-ahead implicit auction. In FBMC, we have multiple PXs. When market participants have submitted bid/offer data to their regional PX, it is the task of the PXs to submit them to the market coupling algorithm. The algorithm is then used to arrive at the overall optimum solution.
- In market splitting, nodes are aggregated into price zones. It is possible for a country to consist of several price zones. In FBMC, all the nodes within a country are aggregated into a single price zone although this is not an absolute constraint.
- In market splitting the transmission network is fully represented when checking for flow feasibility. In FBMC, intra-zonal flows are ignored. In addition, all cross-border lines between two neighbouring countries are aggregated into a single equivalent interconnector. In essence, the network consists of a single node for each county (or modelled zone) and single links between neighbouring countries. Power Transfer Distribution Factors (PTDF) are used to define the locational generation-to-flow relations. When necessary, PTDFs can be adjusted to reflect changes in the network topology and system condition.
- ATCs are calculated through co-operation of all participating TSOs. Cross-border loop flows due to inter-regional nominations are estimated and netted off. An ATC value is released for each interconnection for each direction.

- The simplified model described above is used by the market coupling mechanism to co-ordinate an implicit auction of capacity across the different interconnectors. The objective is to match the submitted bids and offers that maximise arbitrage trade. The optimisation takes into account cross-border loop flows (calculated through the PTDFs) and ATC constraints.
- For annual and monthly NTC allocations a Reference Flow (RF) is defined, that quantifies the active power flow on a considered critical branch after a critical outage (N-1), which would occur under the assumption that no cross-border exchanges between market areas modelled in the load flow model take place. Thus, the RF reflects flows due to the coverage of the TSO-specific system load through domestic generation without additional import or export. The RF is then subtracted by the physical capacity of the interconnector and the remaining capacity is auctioned

3.4.6 Limitations of the Target Model and Flow-Based Market Coupling

One of the drawbacks of Flow-Based Market Coupling (FBMC) is the simplified network model that arises from considering only flows from one zone to another. The efficiency of system operation depends significantly on the quality of the simplifications and whether they can accurately capture all system constraints across different operating points. In the case of FBMC, TSOs have to release capacity across "virtual" flowgates. There is a real risk that the simplified equivalent network of zones and lines fails to accurately represent the underlying physical reality and lead to an inefficient dispatch, which is highly undesirable.

But even if the network is accurately presented this will not resolve an inherent problem with the Target Model and FBMC approach, which is that the amount of capacity available for trade across interconnectors, in a meshed network, will be **market condition dependent**, that is, it will depend on the spatial pattern of generation which will in turn depend on relative fuel and carbon prices, and hence on varying market conditions. The dependency of interconnector capacity on market condition is less problematic for the day ahead market, but it is typically very significant for longer-term transmission rights. This is because market conditions can be predicted with a reasonably high degree of certainty day ahead (although increasing amounts of intermittent generation capacity reduce the level of certainty to some degree), but predicting market conditions with high degree of certainty over the longer term is fundamentally problematic – daily gas prices can change unpredictably and by a factor of 3-4 over a space of a year.

So the amount of long-term capacity on the interconnectors that can be made available to market participants, that is inherent to the design of the Target Model and FBMC, is market condition specific. The capacity offered will not only depend on the state of the transmission system but will be driven by various aspects of market operation:

- Generation maintenance patterns and durations
- Fuel prices and merit order dispatches
- Wind conditions (resolving network access policy for wind generation, discussed in section 2.5, will not resolve this problem)
- Demand level (this may be particularly relevant given the increase in distributed generation of various forms that offset the demand seen by the transmission system and the increasing share of time-shiftable load enabled by smart meters and the acquisition of electric and plug-in hybrid vehicles)

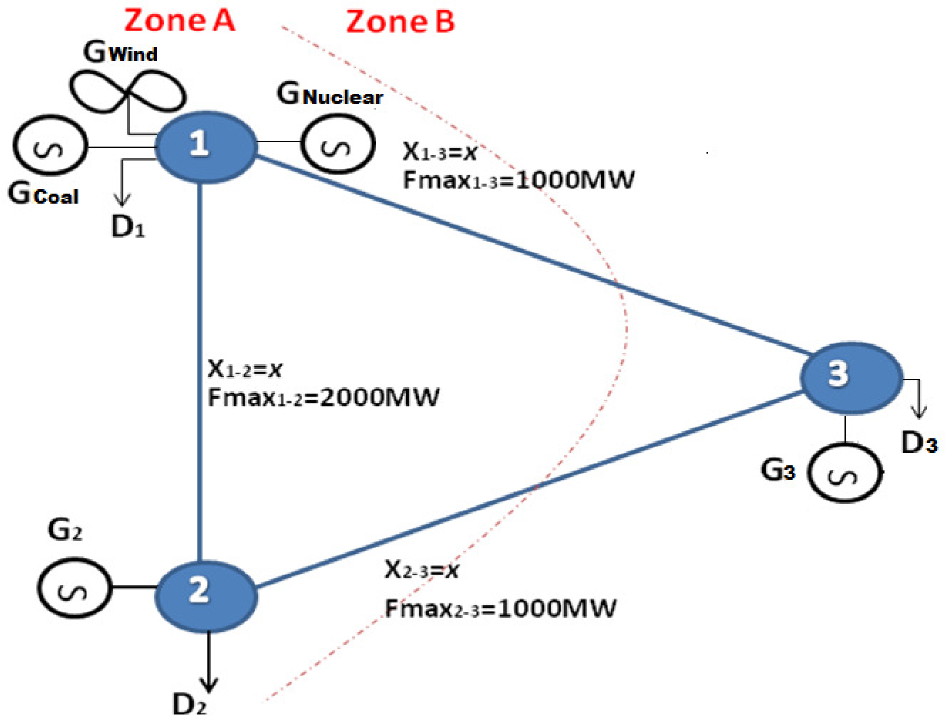
Illustrative examples

As mentioned above the Reference Flow calculation methodology depends on the intra-zonal market dispatch which in turn depends on the *market conditions*. We illustrate this on a simple 3 bus-bar system, divided in two zones (Zones A and B), as shown in Figure 3.6 below. Nodes 1 and 2 are in Zone A, and node 3 is in Zone B, connected in a triangle formation. We assume that demand in Zone A of 2,400MW (located at node 1) can seek to meet its requirements by making contracts with generation in Zone A, where there is 1,800 MW (of various possible types) at node 1 and 3000MW of CCGT located at node 2. Further we assume that demand in zone B of 3,000MW connected to Node 3 contracts with generation in Zone B, comprising CCGT of 3,000MW connected to Node 3. Thus in principle there is a sufficiency or excess of generation capacity, both globally and each zone, but it is not all located at the node where the demand is.

To illustrate the impact of market condition on the available cross-border capacity we assume in the following three examples that the generation at Node 1 is, in the first example, nuclear plant, in the second example coal plant, and in the third example wind plant. We also assume that generators in both zones meet their contract positions for supply of their local demand. Since demand and generation in Zone B are connected to the same node, when generation in zone B meets the demand in Zone B, there is no impact on the flows through the interconnectors. In this example we focus our attention on the evaluation of NTC across the interconnector 2->3, facilitating potential trade of energy from Zone A to Zone B.

- <u>Example 1</u> In this example, an 1,800MW nuclear plant is connected to Node 1, running at full capacity. In order to meet the demand in Zone A, an import of 600MW generation from CCGT in Node 2 will be needed. This operation will produce the following flows: intra-zonal flow 2->1 of 400MW and loop-flow over the interconnectors 2->3 of 200MW and from 3->1 also 200MW. Hence NTC on the interconnector 2->3 in this case will be 800MW. Now suppose that during maintenance of the nuclear plant, that the full 1,800MW is taken out of service. The CCGT at node 1 will produce 2,400MW, which will produce the following flows: intra-zonal flow 2->1 of 1,600MW and loop-flow over the interconnectors 2->3 of 800MW and from 3->1 also 800MW. Hence NTC on the interconnector 2->3 in this case will be 200MW. In this case the operation of nuclear plant creates very significant amount of additional interconnector capacity. Clearly, NTC available will be influenced by maintenance patterns and duration of different plant maintenance strategies of individual market participants. It may not be appropriate that TSOs take any commercial position on this when determining the amount of cross-border capacity that should be offered to the market participants.

Figure 3.6: Two Zone Three Bus Bar example



- Example 2 In this example we consider the situation in which, instead of nuclear, a coal-fired generator of 1,800MW is connected to Node 1. In this case, the available interconnector capacity will depend on the relative differences in prices of electricity from gas and coal generation. When price of coal-generated electricity is higher than gas, the available capacity across the interconnector 2->3 will be 200MW, since the CCGT at Node 2 will run at 2,400MW. In the reverse case, the NTC that TSO can offer will be 800MW, because the coal-fired plant runs at 1,800MW and the CCGT supplying the remainder runs at 600MW.

- Example 3 Finally we consider the situation in which, instead of nuclear or coal-fired generator, we have a wind farm of 1,800MW connected to Node 1. Now the available interconnector capacity will depend on the wind condition. On a windy day, when wind farm runs at full capacity of 1,800MW, CCGT at node 1 will produce the remaining 600MW at Node 2. This operation will result in the following flows: intra-zonal flow 2->1 of 400MW and loop-flow over the interconnectors 2->3 of 200MW and from 3->1 of 200MW. Hence the NTC on the interconnector 2->3 in this case will be 800MW. But on a calm day the CCGT in node 2 will produce 2,400MW, which will produce the following flows: intra-zonal flow 2->1 of 1,600MW and loop-flow over the interconnectors 2->3 of 800MW and from 3->1 of 800MW. Hence the NTC on interconnector 2->3 in this case will be 200MW. In this example, the operation of wind farm creates significant additional interconnector capacity, although if it had been less helpfully located the reverse might have occurred. Suppose now that the CCGT connected to Node 2 in Zone A wishes to compete to supply the demand at Node 3 in Zone B, and therefore wishes to contract for interconnector capacity. But the interconnector capacity from Zone A to Zone B will depend on wind conditions in Zone A: on windy day the available capacity is 800MW but on a calm day drops to 200MW.[49] This issue will exist irrespective of the network access policy for wind generation: in fact in this example, there is more capacity across the interconnector from Zone A to Zone B during high wind condition and less capacity during low wind condition. In the present European network topology, more often the issue is that interconnectors have less available capacity in high wind conditions.

These examples show that, in a meshed network, the amount of cross-border capacity that can be made available to market participants is market condition dependent. This is an inherent limitation of the Target Model design, as it is very difficult to answer the question as to how much capacity should be made available for long-term auctions (in the day-ahead market, however, uncertainty around plant dispatches and hence the amount of NTC will be significantly lower).

As the market conditions drive the amount of capacity over interconnectors that may be available, there are clearly several issues that need resolving:

- Determining / agreeing on the market condition assumptions that should be used to quantify the amount interconnector capacity that can be made available to the network users in the long term;
- Defining the sizes of Zones; and
- Incentive regimes for TSOs associated with the delivery of cross-border capacity.

Regarding the first two issues, these are empirical question and would need to be analysed on a case-by-case basis in order to ensure the robustness of decisions associated with the volume of the cross-border capacity that is made available for long term auctions, so that changes in market condition do not affect significantly the Reference Flow.

Regarding incentive regimes, we stress that if TSOs are required to take commercial risks associated with cross-border capacities that will be delivered far ahead in future, given the Target Model and the proposed NTC calculation methodology, this may lead to very limited volumes of cross-border capacity being offered in long term auctions. Hence, we suggest that the remuneration regimes for TSOs should be designed so that they see their interest lying in maintaining network availability, but not in speculating about the future generation maintenance patterns, bidding strategies, wind patterns etc. Clearly, anything that exposes TSOs substantial risks affected by the choices of market participants, or encourages it to assume risks associated with the position taken, will inevitably lead to it taking conservative views on the available NTC, and potentially undermine the aspirations of the single European electricity market. This issue has also significant implications on the firmness of the TRs, which is further explored in Section 3.8. We would note that the overall manner in

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[49] *One can argue that there is a real physical constraint that the CCGT at Node 2 cannot deliver more than 200MW of power to Node 3 at the same time as delivering 2400MW of power to Node 1, even though there is a total 3000MW of physical interconnector capacity at Node 2, given the system topology and constraints on the connections between Node 1 and Node 3. But in other approaches to electricity markets, the generator at Node 2 would have been able to contract to supply the full 800MW to node 3, and hedge itself against the exposure to the price difference for electricity between node 2 and node 3 for those times when it physically cannot physically deliver it all because of constraints on the transmission system, and that imbalance is supplied via generation at node 3. But the ATC approach means that there are only 200MW of transmission rights available, and the longer term contracting possibilities between generators at Node 2 and consumers at Node 3 are reduced, unless they are willing to remain substantially exposed to the spot market. There is still the potential for short-term trading, but this increases risk to both parties.*

which TSOs are remunerated for providing their services are a matter for member states, but international arrangements can influence it by making rules on matters such as firmness.

The zonal market design and NTC calculation methodology may also create opportunities for "gaming" by market participants. Gaming means the use of apparently perverse strategic choices by market participants (e.g. withholding generation capacity that would in itself be profitable to run, or nominating generation that will be constrained off and receive compensation for not operating) that take advantage of the operation of the rules to make a profit, or disadvantage competitors, and which reduces the efficiency of the wider outcome. In particular, portfolio generators (in importing or exporting zones) could strategically dispatch their assets in order to affect the NTC (either reducing it or increasing it) leading to FTR revenue inadequacy that may be commercially advantageous. This is an area that EU regulators should actively monitor through examining the operating conditions that lead to revenue inadequacies.

We would point out that these problems are mostly resolved in nodal/LMP based market designs, although no market design can entirely remove the risk of the exercise of market power, where such market power exists. In effect, in nodal/LMP systems, subjected to the Simultaneous Feasibility Test, all the physical transmission capacity can be auctioned. It can be shown that the ISOs will be always revenue adequate irrespective of the actual realisation of the market condition and actual plant dispatch at any point in time,[50] provided that the network physical capacity sold is delivered. In contrast, according to the Target Model design, TSOs could be revenue inadequate (in deficit) even if all network assets are made available. Given that the materiality of the impact of market conditions on available cross-border capacity will be influenced by definition of zones, it is hence desirable that regular analysis is undertaken regarding the appropriateness of various zone definitions.

In the following section we present how capacity calculation and allocation is carried out in some systems around the world and highlight any lessons that can be learnt from present experience.

3.4.7 USA Markets

In LMP markets in the US, the process of capacity allocation is similar to the one described above. All market participants have to submit bids and offers for electricity to the ISO. Subsequently, the security constrained economic dispatch problem is solved while taking into account all system constraints. Once the optimal solution is found, the system is dispatched accordingly. It is important to note that in LMP markets this optimisation covers all electricity injections and withdrawals in the system. In contrast, in other methods such as market splitting (where inter-zonal trades do not have to be submitted to the exchange and can be carried out independent of implicit capacity auctions) the optimisation is carried out only on cross-border residual trades. The increased locational price resolution under LMP allows for a more efficient generation dispatch, maximising social welfare of the entire system. Market participants can have a clearer picture of how costs vary per node as well as quantify more accurately any arbitrage opportunities. In addition, a fully nodal system can potentially give more accurate signals for long-term transmission investment and for locating new generation and load.

[50] *That is, irrespective of whether wind blows or not, irrespective of any changes that may have occurred in gas / coal prices that may have fundamentally change generation dispatch, irrespective of which plant is on maintenance and for how long.*

In the US markets, FTRs are allocated to the market participants (consumers, generators, or traders) based on predetermined rules or by soliciting requests and then choosing which to satisfy by an optimisation model or other procedure. The specific method varies from system to system.

For instance, the method used in the PJM Interconnection market is auctioning of FTRs to the highest bidder, with auction proceeds returned to the holders of "auction revenue rights" (Treinen and Papalexopoulos[51]). The auction maximises payments using an optimisation model, subject to satisfaction of simultaneous feasibility (Ma et al[52]). In some markets, there is also provision to allocate FTRs to merchant transmission providers (i.e. commercial investors who construct transmission facilities for profit) who build new facilities that increase the amount of FTRs that can be allocated while satisfying revenue sufficiency ("Incremental allocations"). This device facilitates new economically attractive investment by paying for external benefits that are not reflected in the price differences across the merchant line.

It is important to note that the auction can allocate FTRs on the same line for both directions due to netting. In this way, market participants can take the view that a power flow may be reversed. This netting of FTR obligations allows a large amount of FTRs to be allocated. The PJM market provides a good example of the liquid trading of counterflow FTRs,[53] thus allowing for more capacity to be sold. This increased liquidity, attracts larger amount of trades and participants and contributes to the market efficiency.

3.4.8 Nord Pool

The Nordic market employs market splitting to co-ordinate cross-border trading and allocate capacity on the interconnectors.[54] At the start of 2011, it consisted of 9 price zones (Sweden will move from a single to four zones later in 2011) and is widely regarded as one of the most efficient and successful electricity markets worldwide (although part of this is due to the large hydro reservoirs that encourage intertemporal arbitrage of the value of water and hence power). Elspot, the day-ahead market, is used to integrate the different regional markets. Market participants submit their bids and offers and Nord Pool employs a market splitting algorithm to clear the auction. As mentioned earlier, the objective is to maximise arbitrage trade while respecting all inter and intra-zonal flow constraints. The participating TSOs co-operate on determining accurate ATC values across the zone boundaries. TSOs rely on heuristics and experience as well as recent market behaviour records to calculate the ATC values. Generally, the Nord Pool system is considered to have a radial setup with an expected north to south flow, and thus loop flows are not a major concern for TSOs, simplifying the task of ATC calculation. The resulting auction prices reflect both the cost of energy in each regional market and the cost of acquiring the associated transmission capacity for cross-border trades. Implicit auctions guarantee that adverse flows over the interconnector are minimised and that power flows from low price areas to high price areas.

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[51] *Treinen, R and Papalexopoulos, A (2002) 'Important practical considerations in designing an FTR market', 3rd Mediterranean Conference and Exhibition on Power Generation, Transmission, Distribution and Energy Conversion*

[52] *X. Ma, D.I. Sun, and A. Ott (2002), "Implementation of the PJM Financial Transmission Rights Auction Market System," http://home.eng.iastate.edu/~jdm/ee458/ArevaPJM2002.pdf*

[53] *From Monitoring Analytics (2011), '2010 State of the market report', Independent market monitor for PJM.*

[54] *From http://www.nordpoolspot.com/PowerMaket/The-Nordic-model-for-a-liberalised-power-market/Implicit-auction/*

No FTRs exist in Nord Pool as in the US markets. A way of hedging congestion risk that resembles the locational differential of FTRs is through CfD contracts, issued primarily by generators and financial institutions, and written on the difference of the zonal price and the System Price (the unconstrained system marginal price) to concentrate liquidity, with annual contracts for the next four years (up to and including Y+3). Unlike FTRs, they are not a claim on the congestion surplus and are not linked to the physical capacity of the system. This means that in export zones there is likely to be an excess supply of CfDs from generators relative to the zonal demand by load, while in import zones the converse is true, reducing the volume and liquidity in the market for CfDs.[55]

3.4.9 IFA

IFA, the France-England interconnector, has explicit auctioning of PTRs. The operators auction 100% of the interconnector capacity, subject to scheduled capacity reductions due to maintenance. Since the IFA is a DC link, the available capacity is not affected by loop flows and market conditions, only by physical availability. But as an undersea link, physical availability is much poorer than overland links, in the region of only 95%, so access offered is not firm, rather it is conditional upon availability.

It is up to the operators to decide how to split the volume of allocated rights among the different timeframes. Currently, the typical split of capacity offered between the different auctions is:

- 45% of total link capacity in both directions is offered in long-term year auctions
- 45% of total link capacity in both directions is offered in long-term inter-year auctions
- 10% of total link capacity in both directions is reserved to be released in the corresponding day-ahead auction

This effectively means that up to 90% of PTRs are traded in long-term auctions, leaving a small percentage for the day-ahead auction. Once physical nominations are submitted for the long-term rights, the operators can net off declarations from both sides of the interconnector and allocate the resulting extra capacity in the day-ahead PTR auction. This netting off of submitted nominations is also done for the intra-day PTR auction. Since the the IFA interconnector is a high voltage DC link and can thus be considered isolated from the UK and French electricity systems, since the flow is fully controllable. This essentially allows the operators to allocate the entire link capacity for cross-border trading, with the only risk being unforeseen failures on the link.

But there have been several occasions where adverse flows are observed over the IFA interconnector, as described in Section 3.2.4.

3.5 TRANSMISSION RIGHT DURATIONS

3.5.1 Introduction

Currently interconnector PTRs are sold with at most annual durations. For the majority of the interconnectors, which are auctioned through the two auctioning offices CAO and

[55] *See for example The Nordic Financial Electricity Market, Nodreg, 8/2010 at https://www.nordicenergyregulators.org/upload/Reports/Nordic_financial_market_NordREG_Report_8_2010.pdf*

CASC, the offered durations are annual and monthly. In the England-France interconnector the following durations are offered:

- Calendar annual
- Financial annual
- Seasonal: Winter (October - March) and Summer (April - September)
- Quarterly
- Calendar month

Traders have indicated their desire of being offered transmission rights with longer durations, to match those of the energy market traded products. The Florence Forum PCG (who designed the Target Model) proposed that available forecasted transmission capacity should be sold for the next four years. They mentioned as indicative percentages 10% of forecasted transmission capacity for Y+3 (the third next year), 20% for Y+2 and 40% for Y+1. Some TSOs may be resistant to such a proposal, although they are offered in Nord Pool.

There is a problem of conflict of interest between TSOs and their customers here. Customers should ideally be provided with the range of rights that maximises their economic value, less the cost to the TSO of providing them. The cost to the TSO lies in the elevation of risk by selling longer term rights. But the customers will seek to avoid paying for any increase in risk to the TSO, and the TSO will seek to minimise risk by reducing the amount and duration of capacity obligations unless it has assurances from its regulator that it can recover any shortfall from some defined a credit-worthy source. An external regulator might specify the schedule of rights to be sold, but may not be best placed to determine what is the optimum distribution of rights, which might in any case vary from time to time and place to place. Merchant interconnectors do not have access to regulated revenues (unless these are explicitly provided) and will therefore be even more cautious, particularly for DC under-sea links which, if they fail, may require weeks or even months before they can be restored. Plainly this is an issue that requires further examination as to the best approach to be adopted and it is likely that an incremental approach is best, to avoid the risk of delays as all these issues are resolved and mutually agreed.

3.5.2 US Markets FTR Durations

In most US markets FTRs are also sold with at most annual durations. But in the most mature and liquid market, the PJM Interconnection, they sell long-term FTR auctions, where transmission rights are sold with a maximum duration of 3 years, starting one year after the long-term FTR auction. No FTR options are offered for these timescales. The way the forward capacity markets are organised by the PJM Interconnection differs from what is envisaged under the Target Model. In particular transmission capacity is first allocated to Load Serving Entities (LSEs) who pay for the cost of the transmission network. Then LSEs offer their allocated FTRs for sale in annual and monthly auctions and collect the auction revenues. The allocated FTRs can have much longer durations then the auctioned FTRs. CAISO, for example, allows LSEs to be allocated annual FTRs for the next ten years.

The capacity that is offered in PJM Interconnection's long-term FTR auctions is the residual of what has been allocated to the LSEs. This implies that the total auctioned capacity is significantly less than the annual auctions when all the physical system capacity is auctioned. But it allows market participants, financial or physical, to buy counter-flow

FTRs, thus creating new FTRs in the prevailing flows direction. The volume of auctioned long-term FTRs is comparable to the volume of annual FTRs. Nonetheless, further analysis[56] of the FTRs indicates that the ratio of prevailing flow to counter flow FTRs in the long-term auctions is almost one to one, compared to three to one for the annual auction. This implies that cleared long-term FTRs arise from the netting effect of market participants FTR bids/offers.

This result is of particular importance given that this netting effect at the time of the auctioning is not possible for physical transmission rights or options. But it has the important effect of allowing considerably more competition over a congested interconnector than an ATC approach without netting.

3.5.3 Nord Pool CfD Durations

Nord Pool CfD contracts are not auctioned, but traded as futures or issued OTC (90% of OTC trades in exchange-listed contracts are reported for clearing to the exchange) on the NASDAQ OMX derivatives exchange. There are CfD contracts for months, quarters and the three nearest calendar years. Due to the general low liquidity of the CfD contracts there is not much available data to compare the volume of traded CfDs over different time horizons, although presentations at the May workshop suggested that the turnover of 2 year ahead CfDs is relatively high compared to next year – between 50-90%.[57] The majority of CfD contracts are OTC trades and that the open interest for the CfDs is higher than the turnover. As it is mentioned in the report *The Nordic financial electricity market (Report 8/2010)*[58] if a product category has a higher share of open interest than of turnover, it indicates that much of the turnover in the product category is hedging or long-term trading. This might imply that the longer term CfDs are traded more than short term durations. This indicates that this is not a highly liquid market, with little pure trading or arbitrage to facilitate robust price formation. Actuarially priced CfDs issued by financial organisation are likely to be rather more costly than FTRs backed by a TSO which has a position in the underlying physical product.

In summary, experience to date shows that TSOs in Europe and ISOs in the US are reluctant to auction physical transmission right with longer durations than one year and it is noteworthy that the longest duration contracts are financial (CfDs) in Nord Pool. Nonetheless, the PJM Interconnection, the only market where longer duration transmission rights underwritten by the ISO exist, almost all of the cleared FTRs result from the netting of the prevailing flow and counter-flow bids for FTRs in the auctions. This is not possible when considering PTRs or FTR options. Furthermore, the reluctance of the TSOs to auction longer duration rights results from the significant risk of being revenue inadequate. On the other hand, the experience from Great Britain is that TSOs would also be willing to issue longer term rights so as to have increased customer commitment, since the risk of non-delivery are shared between market participants and the TSO. It may be that an evolution from PTRs to FTRs will encourage a move to longer duration products in response to demand and the gradual appreciation by TSOs that the risks are manageable, at least for terrestrial AC links. Undersea (usually DC and often merchant) interconnectors face considerably higher risks that will be discussed below.

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[56] *Monitoring Analytics, "2010 State of the Market Report for PJM", Section 8, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010.shtml .*

[57] *Presentation of Hans Randen on Nord Pool Spot*

[58] *DG Competition, Report on energy sector inquiry, 2007 Table 17 p. 127*

There is a clear need for an appropriate scheme of sharing of risks in the case of long-term revenue inadequacy, and customers must be required to pay appropriately for the additional risks which are more efficiently borne by a TSO than by a finance house. This could include a combination of an incentive scheme on TSOs as they can control availability of the network, PTR/FTR holders and all market participants. It should, however, be remembered that the congestion revenues provide TSOs with a ready source of revenues to cover the costs of efficient market-based compensation, provided they are allowed to use them for that purpose.

3.6 SECONDARY AND OTC MARKET

3.6.1 Introduction

For efficient pricing in markets, liquid trading of the underlying instruments is essential.[59] In most cases, the majority of transmission rights are obtained in periodic auctions organised several months before delivery. It is important that the market allows participants to reconfigure their positions subject to new information made available closer to time of delivery. Well functioning secondary markets are an important feature of an efficient market and lead to better price discovery. The need for liquid secondary trading is highlighted by the increasing penetration of intermittent sources of energy in Europe. Being able to tune system dispatch to accommodate cheap generation across all timeframes is critical.

3.6.2 USA markets

A liquid secondary FTR market, involving frequent reconfiguration auctions, is a significant way through which better convergence between forward and spot prices of the congestion rents can be achieved.[60] Currently, however, secondary markets that enable reconfiguration and re-trading of FTRs are very thin (this holds true for example for the PJM Interconnection, which is the most liquid FTR market). More specifically for the PJM Interconnection:

- Market participants can both buy and sell existing FTRs through the bilateral market administered by PJM Interconnection, or they can trade FTRs among themselves outside the formal market.
- For FTRs option/obligation administered by PJM Interconnection, sink and source definitions must remain the same, but volume can be broken down to 0.1 MW.
- Duration can also be altered as long as the new start and end times are within the original FTR duration.

In the US, typically 100% of capacity is released at the earliest date for sale as FTRs. Reconfiguration auctions are often auctions at which the TSO releases additional capacity not previously known to be available, or buys back capacity it now no longer has available, eg for reason of outage or maintenance. They may also offer retrading opportunities for holders of rights with greater liquidity than at other times. For the EC, we are

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[59] *N. Gandhi, 2008, "FTR/CRR allocation/auction strategies and methodologies: The perspective of a competitive electric provider," Pittsburgh, PA, IEEE Power Engineering Society Summer Meeting*

[60] *S. Deng, S. Oren, A.P. Meliopoulos,2010, The inherent inefficiency of simultaneously feasible financial transmission rights auctions, Energy Economics Journal, 779-785.*

recommending that ATC is sold, which will typically increase as time proceeds, as certainty improves. But it might occasionally happen that ATC reduces because of planned maintenance, or other known outage. So in the EC reconfiguration auctions might normally be releases of additional capacity, and only occasionally withdrawals. They might also offer a periodic time of higher liquidity for right holders to retrade than trading opportunities at other times.

Trading hubs defined for FTR trading increase liquidity (Treinen and Papalexopoulos) by narrowing down the definition of tradable products. There have been also proposals to allow secondary trading of FTRs of non-identical source-sink definition subject to some adjustment factor determined by the respective PTDFs.

3.6.3 Nord Pool

The primary hedging instruments in Nord Pool (forwards and CfDs) are futures and OTC contracts traded through the power exchange. They are subject to resale and secondary trading as any other futures contracts, since the trading does not require any involvement of the TSO. In practice, such secondary markets are not very liquid, which is generally attributed to the fact that there are no counterparties that have a natural hedge. However if sufficient liquidity is present, secondary trading can be carried seamlessly through the exchange since the settlement of such financial contracts is decoupled from the physical dispatch of the system.

3.6.4 IFA

A user that acquires PTRs for the France-England interconnector in an auction may relinquish them for use by other eligible users in the secondary market. There are two mechanisms to achieve this:

- Resale of capacity units: This enables a capacity holder to sell his units in a forthcoming auction (e.g. capacity units acquired in an auction for annual rights can be sold in a forthcoming auction of monthly rights). To do this, the holder submits a resale request to the Operators for a forthcoming auction. The price the holder will receive is the clearing price of the auction in which the resale is made.
- Capacity Transfer Notice (CTN): This effectively allows bilateral trade of capacity units between users. Following the publication of auction results, the winning bidder may submit a CTN to the Operators, requesting transfer of units to another user. If the CTN is accepted, the user becomes the new unit holder.

Secondary market trades, such as CTN, concerning long-term units for a specific contract day D can take place until 15:30, two days ahead of delivery date D (D-2). The IFA operators then issue the final Interconnector Capacity Entitlement (ICE) to each user to inform them of the maximum amount of long-term units they can use. Subsequently, the users have to submit their Mid-Channel Nominations (MCN) until gate closure time (9:30 on previous day D-1), informing the operators on the amount of interconnector capacity they intend to use and the associated energy injections in the system. This process is repeated for the day-ahead and the two intra-day auctions, allowing capacity holders to trade in the secondary market and optimise their position in all timeframes.[61]

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[61] *This process is described in more detail in the IFA Access Rules, Issue 7.0 (2007), http://www.nationalgrid.com/NR/rdonlyres/5DEEDCE2-52FC-453C-988F-F1973B9F696F/37205/IFAAccessRulesv7025September20091.pdf*

As described earlier, secondary markets are essential for increasing liquidity. In some market setups, secondary trading has to be overseen by the TSO to validate that reallocation of transmission rights can be physically supported by the system. In other markets, secondary trading does not require the involvement of the TSO and relies on bilateral trade.

3.7 OTC AND TRANSMISSION RIGHTS

3.7.1 Introduction

This section examines whether offering FTRs instead of PTRs would impede OTC and bilateral trading of energy.

3.7.2 USA markets

Electricity forwards with short maturity like 1 hour or 1 day are often physical contracts, traded in the physical electricity markets such as the PJM Interconnection power pool market and the energy balancing market operated by CAISO. Those with maturity of weeks or months can be either physical contracts or financial contracts and they are mostly traded through brokers or directly among market participants, ie, traded in the OTC markets.

Every LMP-based system can fully accommodate bilateral trading and, indeed, most trading in LMP-based systems occurs bilaterally. A party is exposed to the same price differential whether it schedules energy for a bilateral transaction or buys/sells energy in the spot market. A generator at node A wishing to transmit energy to node B can choose to self-dispatch or participate in the pool,[62] selling energy at point A and buying at point B. In both cases, the congestion charge is equal to the LMP differential. For both parties to receive the agreed contract price, it is essential that they purchase FTRs to cover the agreed transaction volumes and thus fully hedge this congestion risk. As mentioned in Section 3.2.5, bilateral trading is in many cases the preferred option of market participants since it does not involve exchange trading fees and does not expose them to pool liquidity risks.

3.7.3 Nord Pool

In the case of the Nordic region, the majority of forward energy trades are realised through OTC contracts, and are primarily used for large volume trading. OTC contracts of standard type (i.e. products that can also be traded in Nord Pool such as base-load or peak forward contracts) can be declared and cleared through Nord Pool's clearing house NASDAQ OMX, eliminating counterparty risk. Most parties that use OTC contracts choose to do so to eliminate counterparty credit risk. It is estimated that non exchange-listed OTC contracts account for less than 10% of total OTC volume and this figure has been steadily decreasing over the past years.

Some more specific data for the Nordic region:[63]

- In 2009, the volume turnover in Nord Pool was about 2,200 TWh (five times the Nordic electricity consumption). 56% of this was due to power exchange trades and 44% was due to OTC products.
- In 2009, the value turnover in Nord Pool was about € 70 bn. About 60% of this was due to power exchange trades and 40% due to OTC products.

[62] *W. Hogan, 2000, "Responses to Common Questions About LMP and FTRs, Flowgate Rights and LMP/Flowgate Hybrids", Harvard University*

[63] *Data from NordREG, 'The Nordic financial energy market' (2010)*

- The number of transactions in 2009 in Nord Pool was about 180,000 (700 transactions per trading day average). About 70% of transactions were for power exchange trades and 30% for OTC products.
- In 2009, the average volume per transaction for exchange trades in Nord Pool was about 10 GWh. For OTC trades, it was considerably higher at about 23 GWh. This indicates that the exchange has a higher market share for smaller trades. OTC products are primarily used for larger trades.

Generally, there has been an increase in both OTC and PX trade during the past years in the Nordic region. In the table below, we show traded volumes for forward contracts in PXs and for OTC brokered contracts. We can see that the volume traded in Nord Pool is comparable to the on-going OTC trades, whereas in other markets where trading through PXs is not considered such an established practice yet, OTC trade is the dominant way of selling forward energy contracts.

Figure 3.7: Payoff Traded volumes in futures/forward contracts as a percentage of electricity consumption (2004-2005)

	Power exchanges	OTC brokered	Power exchange + OTC
Nord pool – Nordic region	196%	327%	523%
EEX – Germany	74%	566%	639%
Endex – Netherlands	39%	509%	548%
Powernext – France	6%	79%	85%
UKPX – UK	1%	146%	147%

Source: The Nordic financial electricity market (Report 8/2010) Table 2

3.8 TRANSMISSION RIGHT FIRMNESS

3.8.1 Introduction

Financial firmness of any contract involves definitions of the conditions under which full payoffs are not provided, such as *force majeure* conditions, or inadequacy of congestion revenue to support the rights. Firmness of transmission rights is deemed as highly desirable so as to facilitate liquid forward and secondary market and efficient long and short term pricing.

In the case of PTRs with a UIOSI provision, the firmness of the contract is associated with the compensation that the right holder receives if the nominated capacity is not available. If the compensation is equal to the area price difference then the PTR is a perfect hedge and 100% financially firm.

But, there are two important distinctions we must make before deciding on the extent to which a high level of firmness is desirable. The first is the distinction between regulated and merchant interconnectors. Regulated interconnectors have the potential, if allowed by the regulator, to recover short-falls from transmission charges in the event of interconnector failures, or to maintain reserves from previous congestion surpluses to cover such failures, rather than investing them or returning them to transmission users, as currently required. Merchant interconnectors have no such revenue stream, and are likely to view the financial risk of offering firm contracts as prohibitive, unless they can offload them via re-insurance. High levels of firmness impose a degree of risk, and it is difficult for a narrowly-focused merchant interconnector to accept that risk. It would also infringe merchant's property rights to impose new risks on merchant interconnectors that they had not accepted when entering into the arrangements to allow them to build the link, which would typically be licensing arrangement.

The second distinction is between terrestrial interconnector links (normally AC) and sub-sea (normally DC) links. Often the sub-sea links are also merchant lines but there is no necessity for the two distinctions to coincide. Terrestrial links can normally be repaired rapidly, while a sub-sea failure may require a major effort and considerable time to restore. The financial risk of offering firm contracts and then losing a line for a day or two may be modest, and readily covered by normal congestion surpluses, but the financial risk of several weeks or months payment may be excessive, not just financially, but in terms of the economic cost of breaching the contract. When the link is not available, or only partially available,[64] the price difference between the markets linked might be rather larger than it normally is, so the value of fully financially firm FTR would be greater during an outage than generally, thus accentuating the risk.

Clearly in the case where links are normally expected to have substantial downtime (and in the case of IFA downtime appears to be in the region of 5-7%), link owners need to be able to contract with their customers in a manner that properly reflects the intermittency of the link. Customers that desire a high level of compensation for link downtime will need to pay an appropriate premium for receiving such a level of service, whereas others may prefer to pay less and be prepared to receive intermittent service. Ideally contracts should encourage the link operator to time any scheduled or avoidable downtime at periods most convenient to customers.

3.8.2 Financial Firmness of PTRs

Currently, a disturbance causing lower actual transmission capacity is considered as *force majeure* for current PTRs. This implies that compensation is not equal to the market price difference, but either the PTR is derated proportionally or bought back from the holder at the price of purchase. This in essence caps the exposure of the TSOs to capacity unavailability and all PTR compensation can be funded by the PTR auction revenues. For example, capacity unit curtailment on the England-France interconnector is done *pro rata* for all unit holders in the following order:

- First, Intraday nominations
- Second, Day ahead nominations
- Last, Long-term nominations

Curtailed unit holders are paid the initial purchase price of the curtailed units. This means that capacity units are not fully firm. Participants take this into account and bid adjusted values on the auctions reflecting the basis risk due to the non-firmness of the rights.

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[64] *The IFA, for example, is in practice several parallel connectors and usually it loses only part of its capacity due to an outage or maintenance.*

Nonetheless, overall, IFA would claim a good track record of capacity availability. It has been consistently over 93% for the past 5 years implying that this basis risk is limited. However, this might reflect the fact that the long-term auctioned capacity is a fairly small percentage (45%) of the physical interconnector capacity as well as the fact that the IFA is a controlled DC link and that the power flow is independent of the intra-zonal trades.

3.8.3 Financial Firmness of FTRs

It is expected that since FTRs are financial contracts then they would be subject to credit risk only. It can be proved that the SFT guarantees that if all the outstanding FTRs are exercised simultaneously to support physical transfers between their corresponding sources and sinks then all these transactions can be supported by the physical grid, i.e. no transmission constraint will be violated.

When the topology assumed for the SFT is the same as the topology used in the real time dispatch, congestion revenues collected by the ISO will be "adequate" in the sense that they will be sufficient to cover the financial settlement of all outstanding FTR obligations and options.

The proof of revenue adequacy is based on the "separating hyperplane principle" of convex optimisation and relies on the assumption that the SFT feasible set (nomogram) is convex. Nonetheless, if the system topology changes for any reason (whether due line outages and/or controllable devices) then the revenue adequacy might be compromised. Revenue inadequacy occurs when the congestion surplus plus any negative FTR payout is lower than the positive FTR claims. This implies that revenue adequacy will also depend on the credit risk posed by different market participants (usually speculators) whose FTR obligation results to a negative payout.

In practice, in nodal markets in the US, in cases of revenue inadequacy the revenue shortfall is covered in the following ways:

- Full payment to FTRs based on nodal prices and uplift of the shortfall to sellers or buyers of energy (full funding approach)
- Pro-rate settlement to all FTRs to cover shortfall ("haircut" approach)
- Inter-temporal smoothing of congestion revenue accounting by carrying over revenue surpluses and shortfall over an extended time period

In all but two markets the "haircut" approach is followed. This implies that in practice FTR holders face a similar basis risk as the PTR holders in the European markets. The two exceptions are the in NYISO (New York), where the shortfall is allocated to the transmission owners and in ERCOT (Texas) where it is socialised to load.

In ISO-NE (New England) and PJM Interconnection, revenue adequacy has in general been very good, with 100% revenue adequacy in 2008, 2009 and 97.7% in 2010. Nonetheless, in MISO (Mid-West) for 2006-2008 and NYISO for 2005-2008 revenue shortfall was over 10% and 7% respectively.

According to Oren (2010)[65] all the above shortfall allocation methodologies in essence socialise the cost and might create opportunities for gaming. He suggests that one of the following approaches be used to avoid the gaming pitfall:

- Pro-rate settlement to FTRs based on impact of de-rated lines (flow-gates)
- Full funding of FTRs and assignment of shortfall to owners of de-rated lines (flow-gates)

He suggests that an increase in line capacity used for the purpose of the SFT can be "virtual" and supported by short positions on flow-gates, just as an increased number of available FTRs between two points can be underwritten by counter-flow commitments. Such instruments are ideally suited for transmission owners (TOs) who are in a position to upgrade the line or maintain it so as to increase its real time rating. Short flow-gate positions provide incentives for incremental improvements and maintenance that can enhance real time transmission capacity or can finance planned upgrades and investments that will alleviate congestion on the shorted flow-gates while enabling the ISO to issue long-term FTRs against such upgrades, ie sell insurance/options against particular Flow-Gate Rights (FGRs).

In any case, revenue shortfall is attributed to the underwriters of the short flow-gates avoiding the possibility of gaming. Nonetheless, the findings are theoretical and there has not been experience with short flow-gates.

3.8.4 Financial Firmness of CfDs

Since the majority of CfDs (OTC or futures) are exchange cleared financial instruments they are in essence 100% firm. The TSOs are not exposed to the revenue adequacy risks and market participants are not exposed to credit risk since the derivatives exchange guarantees the payouts.

Nonetheless, price area CfDs in the Nord Pool, which is the only market that they have been implemented, are thinly traded implying that although they are 100% firm there is significant liquidity risk for market participants who wish to close out their CfD positions.[66]

3.8.5 Financial Firmness of Transmission Rights under the Target Model

Although in the majority of LMP/FTR market designs transmission rights are not fully financially firm, with haircuts applied to their holders, there are several reasons why this might not be appropriate for progressing towards the Single European Electricity Market. Some of these points are analysed below:

3.8.6 Financial Firmness of Access for Interconnectors and Intra-zonal Network

In most European countries the intra-zonal access to transmission network is firm, with varying forms of compensation for constrained-off plant that was denied full access due to inability of the network to absorb their output. On the other hand, access to the cross-border interconnection capacity may be treated as not fully firm, even in the situation when intra-zonal and cross-border assets are of similar technologies (we discuss separately the case of undersea cable interconnection). Developing a consistent approach to the firmness of access

[65] *S. Oren, and K. W. Hedman,(2010) , "Shortfall Allocation and Transmission Performance Incentives in FTR/FGR Markets", 2010 IREP Symposium- Bulk Power System Dynamics and Control*

[66] *Clearly the Nordic CfD market is more liquid than the markets in other existing access rights. An important of aim of moving to FTRs would be to achieve a higher level of liquidity than currently exists in the Nordic CfD market.*

to interconnectors and intra-zonal network would be in line with the objective of the delivery of single European electricity market.

One approach might be to say that TSOs should not discriminate between the level of firmness they offer intra-zonal and interconnection customers. This has the complication that it is likely that the local terms of trade may differ somewhat at each end of the interconnector. In order to promote cross-border trades and the aspirations of the Single European Electricity Market it might be desirable to develop a consistent approach to the firmness of access to interconnectors and intra-zonal network (i.e. firm transmission rights), so that cross-border energy trades can be hedged efficiently.

3.8.7 Financial Firmness and NTC calculation

As discussed in Section 3.4, calculating long term NTC involves making various assumptions about market condition as well as intra-zonal constraints, as these will impact the amount of cross-border capacity that can be made available to market participants. The basis for setting out the assumptions for NTC evaluations needs to be developed, and the regulators could set out firm guidelines for Reference Flow determination as part of the NTC calculation methodology.

We would note that formally determined Network Codes are difficult and slow to revise, whereas this is the kind of material that would need to be a living document and capable of refinement from time to time. It would be preferable if it resided in some other kind of institutional form.

We believe it would not be appropriate for TSOs to adopt a commercial position regarding the outcome of market dispatch year(s) ahead: their commercial interest lies in determining it conservatively. This tends to increase their income from transmission rights. Often national regulators do not find this inconvenient, since it enables them to reduce intrazonal transmission charges. But this favours intrazonal transmission over interzonal transmission and is inconsistent with integration of the market. Given the desire to maximise the release of long term transmission capacity, to the same level as intrazonal capacity, TSOs should be protected from the financial implications of the declarations they make, provided those the declaration conforms to appropriate principles. It is therefore desirable that that the capacity TSO’s declare available should be a matter of governance, i.e. based on rules set out, as opposed to the application of their commercial discretion. Any short-term discrepancies between assumed (calculated) and realised interconnector capacities due to changes in intra-zonal dispatch and the resulting financial revenues and losses, could then be covered through the regulated revenue of the TSOs. If the rules were correctly balanced, in the longer term it should not be revenue inadequate, if well managed.

In addition, it might be appropriate to consider for TSOs to have some financial incentive to release extra long-term capacity on top of what is prescribed under the NTC calculation methodology. This would allow TSOs to issue a maximum volume of TRs without taking upon themselves risks, which they cannot control. Given that in any case the financial risk for offering this capacity would be passed through to consumers it would be consistent to make these transmission rights 100% financially firm.

3.8.8 Financial Firmness, Force Majeure and Capacity Availability

If capacity is not due to be available because of planned maintenance, or known long-term outage, or any other reason, then there should be no obligation on the TSO to sell this capacity at that time. In practice, with TSOs selling capacity long in advance, it might already have sold it. This can be managed through orderly buy-backs, if sufficient notice is available. In principle, such buy-backs could be done through the secondary market. However better transparency and efficiency is best served by the TSO buying the rights back in a reconfiguration auction, provided the moment has not arrived after which capacity is deemed firm. Adoption of this method of adjusting ATC to capacity changes, whether increases or reductions, as policy will enable the TSO to observe when capacity is not valued highly, and schedule maintenance at low value periods, thus minimising its buy-back costs. If the TSO had known of the capacity unavailability in advance, it would never have sold it, so buying it back from a liquid market at market price is essentially equivalent to not selling it in the first place.

Providing the physical capacity (through maintenance, investment or operation) of regulated assets, and ensuring their economic availability, is the responsibility of the TSOs. Consequently, the way in which TSOs are regulated can aim to maximise the physical availability of the transmission assets, or, perhaps better, maximise the physical availability at times when the demand for them is of most value. Thus the details of availability management, and charging for use of the assets, and determining how those charges are recovered from different classes of customer, ultimately lies within the responsibility of national regulators to determine.

As indicated previously, completion of the internal market in electricity requires that there should not be undue discrimination between intra-zonal customers and interconnection customers. At the moment, intrazonal customers often benefit from fully firm capacity in the transmission system, and the costs of delivering that are averaged over customers. Cross-border transmission is not essentially so different from intra-zonal capacity that it should suffer worse terms, except perhaps in the case of specific technologies, eg undersea links, that are known to be materially less reliable. In any market, such undue discrimination between national and international trade is inconsistent with the common market, and an important task of the EC is eradicating such undue discrimination in order to complete the internal market.

So if a national regulator determines that national transmission customers should have a particular standard of firmness of service, and recovers the cost of that in certain ways, then it must do provide something essentially similar and non-discriminatory for cross-border customers. Transient losses of capacity occur both within zones, and from one zone to another, the difference being that the costs of internal congestion are frequently not transparent and recovered from customers in a non-transparent fashion, whereas the congestion between zones is more transparent, and will become more transparent still with FTRs rather than PTRs. Whilst the EC probably cannot insist upon TSOs making congestion costs transparent intrazonally, it should insist on interzonal transfers obtaining at least parity in treatment.

In the very short term the loss of a large amount of physical capacity can result in a reduction of intra-zonal transfers, so that the TSO's income from the congestion rents it earns from those transfers no longer covers the cost of paying out on firm FTRs, which it is now too late to buy back. When the congestion rents become financially inadequate to pay out on the FTRs, a TSO can be seriously financially damaged if it had no way of recovering that pay-out from its customers in some way. In the case of internal congestion, such methods of recovering losses to firm transmission customers exist, but are non-transparent.

The matter may be more transparent in the case of interconnection customers, but this should not disadvantage them.

The way in which the TSO should deal with this is a matter for the national regulator to determine, given that such regulators determine how the costs of service of TSOs are imposed upon customers, and what risk should exist. For example, to the extent that a TSO's cross-border trade is more than financially adequate, a fund of surplus congestion rents can build up and be used to draw down on in periods when it becomes financially inadequate. We would recommend such an approach, but that does not mean it should necessarily be required: unless the EC is able to demand a common approach it is essentially it is for national regulators to decide precisely how they do this, within an overall approach to firmness for zonal and intrazonal customers that does not discriminate unduly. Many regulators currently take advantage of this surplus congestion rent to reduce use of system charges to the generality of customers, a "single till" approach to charge regulation. The concept of the single till suggests that the regulator could equally allow any congestion shortfall to fall on the generality of customers. The "congestion surplus fund" would be an example of a "dual till policy". Another dual till policy would be to recover any congestion shortfall from cross-border transmission customers by a "haircut" on the FTRs. A haircut might only apply once the congestion fund had been exhausted. Alternatively, the haircut might be applied routinely, but in such a case, one would also expect the congestion surplus to be returned to interconnection customers in some way.

Thus we see that TSOs can manage adjustments in capacity for unforeseen outages and maintenance not planned for by a variety of methods, and handle the financial consequences, with different risk/reward consequences for different customers. It is the responsibility of the national regulator to set out the methods, and adjust the methods so that there is no material discrimination between intra-zonal and interconnection customers. Currently capacity management is often handled in part by rather blunt *force majeure* terms, but we see that this is not necessary, instead regulators should be required to be offer equivalent firmness to interconnection customers that they offer for intra-zonal customers. There are methods of recovering the costs of this firmness, and those should be non-discriminatory too.

If the Commission can observe that the greater number of member states would wish to maintain fully firm internal transmission rights, then the Commission may wish to aim to achieve some more uniform rules on the firmness of cross-border interconnection rights, which would be aim to deliver a typical level of firmness as offered nationally, rather than demanding non-discrimination. This may be a quicker and easier method of achieving market integration than assessing whether individual TSOs are discriminating unduly and taking action to require them to cease. In some cases, this might in practice be firmer than intra-zonal rights, or at least more generous in the way it allocates the costs of any congestion shortfall in relation to the FTRs across TSO customers. The Commission might justify such a uniform rule on the basis of better, more simply, and more quickly improving the integration of the market.

3.8.9 Financial Firmness of Merchant Assets and Sub-sea Cables

By definition revenue of merchant transmission lines is not regulated and the commercial viability and profit of the project is driven purely by the congestion surplus. In LMP/FTR markets, merchant line owners are allocated the TRs resulting from their investment, which allows them to collect the congestion surplus. This implies that if the line capacity is not available than the owners of the merchant lines face the financial consequences due to reduced power flow and congestion surplus.

If merchant line owners choose to sell their TRs to market participants, these could be of different level of firmness, reflecting the design and technology characteristics of the interconnector. The volume of TRs and the price at which the TRs are sold represent commercial decision of merchant transmission owners and this can reflect the amount of financial risk they are willing to shoulder by balancing forward sales of TRs and the payouts that may be collection of congestion surplus. Furthermore, merchant link owners could choose not to sell forward any TRs and enter OTC CfD agreements with market participants with varying degree of firmness.

It should be noted, that due to loop flows and negative externalities, merchant links have the potential to reduce social welfare. This is one of the reasons why merchant projects are subjected to regulatory approval in the EU.[67]

We have already noted that the technical characteristics of sub-sea DC cables differ significantly from terrestrial links. The repair times may be significantly longer reaching up to several months compared to a few days for terrestrial links. This implies that offering the same level of firmness for technically different assets might not be appropriate. In any case, the spirit of merchant links is that they make commercial decisions on the investment and it is therefore appropriate that they make commercial decisions on the degree of firmness they are willing to offer, unless they reach an agreement with the regulator to be compensated in exchange for offering firmer access terms.

In particular, an auction of transmission rights, subject to a Simultaneous Feasibility Test (SFT), could be devised that would offer rights of various firmness. Market participants could bid different prices and TSOs offer different volumes for varying degrees of firmness. The SFT would ensure the TSO revenue adequacy as well as maximise the value of the transmission system to market participants. However, it must be pointed out that such a formulation of an auction and SFT of transmission rights with varying firmness has not yet been developed.

Another option would be to move to a system of FGRs, where the firmness of each FGR would reflect the technology characteristics of the specific asset. Since FGR auctioning and secondary trading does not require an SFT such an approach could be easily implemented but would carry all the disadvantages of the FGRs, as analysed in Section 3.2.

The final option could be to guarantee 100% the financial firmness of all the TRs and deal with revenue adequacy and risk of asset availability through the performance base regulation of TSOs in the same way as terrestrial links. The availability clauses could be adjusted to reflect the technical reality of the assets. Such an approach would be relatively straightforward to implement but would in essence socialise the financial losses of non-firmness giving way to potential market distortions.

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[67] *W.Hogan,(2011) , "Transmission Benefits and Cost Allocation", Harvard Kennedy School paper, May 31, 2011.*

4. ANALYSIS AND RECOMMENDATIONS

4.1 SHORTCOMINGS OF THE TARGET MODEL

There is an inherent problem with the Target Model and Flow-Based Market Coupling (FBMC) approach, which is there is not a well-defined quantity of available capacity across connectors to be sold ahead of time. The amount of capacity that will be available across interconnectors in a meshed network, when specified by this bilateral approach, varies from moment to moment according to transient market conditions, dependent upon loop flows and congestion inside zones. The implementation of Flow-Based Market Coupling itself can, and we stress should be, based on a detailed network model, to accurately represent the underlying physical reality of the network, as otherwise this may lead to an inefficient dispatch, which is highly undesirable.

But even if the network is accurately presented in FBMC, this does not resolve the problem of specifying the amount of capacity available on interconnectors. Intermittent generation in particular results in difficulties in predicting market conditions with a high degree of certainty, particularly over the long term.

The capacity that can be offered in the long term auctions will not only depend on the availability of the transmission system but will be driven by various aspects of market operation including generation forced and maintenance outage patterns and durations, fuel prices and merit order dispatches, changes in wind generation outputs and changes in demand. Any discrepancy between forecasted and actual realisations in any of these factors will lead to revenue discrepancies (over or under recovery of revenue associated with FTRs).[68]

This has resulted in the situation whereby on the Spain-Portugal border, where FTRs have been implemented, only about a quarter of the maximum physical capacity is sold ahead of time, because, from time to time, that is all that is available. Nevertheless, for a proper integration of the Spain and Portuguese markets it can be understood that to make only a quarter of the capacity available in the general case is a substantial restraint on level of integration across that border, in particular longer term cross-border contracting, that really ought to be supported by the level of capacity available. The fact that there are now rarely significant price differences between Spain and Portugal is a strong indication that those markets ought to be better integrated. In effect, if Spain and Portugal were a single country it is unlikely that such a restraint on contracting from one region to another would exist.

The key concern is therefore that this inherent problem with the market design may undermine the overall objective of the enhancing long term cross-border trades as a key element of the development of the EU single electricity market. In addition to the need to define the rules for evaluating cross-border capacities that should be made available to market participants in long term auctions and the definition of zones, very careful consideration of alternative options for handling of revenue inadequacy and TSO incentive scheme will be a key to mitigating the effects of this market design problem efficiently, while facilitating the long term cross-border trades and facilitating the progression to a single EU electricity market.

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[68] *We point out that this problem does not exist in nodal/LMP based market designs*

Thus the Commission should understand that our recommendations can help to improve the level of integration of the market in electricity, but there will remain impediments to a fully integrated market in electricity that lie outside the domain of this project. But it is possible that our recommendations might encourage movement in other areas to improve integration. For example, an aspect of our recommendations is that TSOs will be exposed to greater financial risk than currently. We believe that this is appropriate, because they are able to manage this risk, and better able to reduce it that other participants in the market. But they would be less exposed to risk if they made changes which facilitated the better integration of the market, for example by increasing the zone granularity, increasing capacity, or other changes to methods that more closely reflect the underlying physics.

4.2 TARGET RECOMMENDATION

By "target recommendation", we are referring to our recommendation of the arrangements is something, like the Target Model, that would be a target to achieve. There will be need to be time to transition to such arrangements, especially in markets which cannot yet achieve Flow Based Market Coupling (FBMC), which is a precondition for our recommended arrangements.

4.2.1 FTR/PTR

FTRs have several advantages over the present system of PTRs for trading over interconnectors and no obvious substantive disadvantages, even if PTRs were reformed to implement the minimal requirements to mitigate market power described below. As a general rule, financial contracts have lower transaction costs than physical contracts and can more readily be transacted through clearing houses that reduce counter-party risk. Part of that derives from the requirement that they need to be standardised to be liquid, and standardised PTRs would share similar advantages, although arguably to a lesser extent. Their main advantage is that a standard two-sided FTR is automatically a firm obligation and as such can be netted to release a potentially far larger market on either side of any interconnector.

Another advantage of FTRs over PTRs is that PTRs relate to a specific interconnector, whereas an FTR relates to a zone-to-zone transaction, without having to specify by what route the electricity travels from one zone to the other. This benefits both the TSO in being able better to calculate ATC, and the user, as not having to worry about the specific route either. Further FTRs (as obligations) are additive, so if FTRs from one zone to another is not available, or the market is thin, one can purchase a chain of FTRs from one zone to another zone by any plausible route and it makes no difference, unlike with PTRs. Finally, another key advantage of FTRs is transparency, because FTRs are always redeemed at the benchmark prices.[69]

As appears to have been widely appreciated and accepted, granting the holders of PTRs the right to withhold capacity (which arises because of the ability to nominate a PTR) confers market power and allows the price difference across the interconnector to be higher than would otherwise be the case. In general that is undesirable, although it can be defended in certain cases as a second-best[70] way of helping to finance a merchant interconnector. If that

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[69] *Even if the user takes advantage of the by-pass arrangements we suggest at Section 5.2.*

[70] *"Second-best" does not mean "inferior", rather it means the best that can be achieved when certain constraints placed upon the arrangements must be respected. Most commonly the term is used when finding the best that can be achieved,*

is considered the best practical way of enhancing interconnection, the fact that it confers some market power (as do patents) requires derogations under existing EC regulations.

It is often argued that a working system with FTRs would require cross-border trading to be conducted through the PXs, similarly to the mandatory nodal gross-pools. It is recognised that any type of compulsory PX would not be in line with the philosophy of the bilateral models that dominate EU electricity market designs. There is an additional concern that compulsory PXs would increase the costs of cross-border trading. This could be easily overcome by allowing market participants to inform TSOs of their intentions and nominate self-dispatch trades (to the TSOs) including volume, injection and withdrawal points. After day-ahead FBMC is cleared, self-dispatched market participants would pay a cross-border access charge equal to the zonal price difference between their injection and withdrawal points. Market participants would be able to hedge this access charge through purchases of FTRs. The self-dispatched trades would be included in the market-coupling algorithm as must-accept bid and offers, and the rest of the market would be cleared. In this way, PX participation would not be compulsory and no extra costs would be incurred for facilitating long term cross-border bilateral trading. PXs would continue to facilitate voluntary trading of the residual market, as is the case at present.

Alternatively, this could be resolved by considering an alternative market design that preserves the bilateral nature of the EU electricity markets by decomposing electricity prices into their energy and congestion /access components. The market participants would trade energy bilaterally from between zones, and at the gate closure inform the TSOs of their intended injection and withdrawals. Through balancing the grid, by accepting bids and offers from generators (to increase and reduce the power outputs) to maintain system security, area prices will be established. The market participants would then be subjected to an access charge equal to the price difference between their zones. When the participants hold FTRs between the zones, they will then be compensated, and maintain revenue neutrality. It can be shown that such a market design is equivalent to a Zonal/Nodal gross pool but based on bilateral trading.

The key advantages of this design are:

- The bilateral nature of the electricity market is preserved
- The only institutional change required is the establishment of a common and integrated balancing mechanism to compute the area prices
- The role of the PXs as residual spot market trading platforms is preserved
- The implementation of the Single Electricity Market would be straightforward without the need to establish a mandatory gross pool and deep market harmonisation: market participants in different location would be able to trade bilaterally within the Single Electricity Market as long as the access charge is paid

The access charge faced by the market participants would make it possible to hedge by acquiring FTRs between their respective zones.

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subject to the constraint that it is operated in a way to recover a certain level of costs. Applying the target recommendations to merchant interconnectors would frequently expose them to too much risk for the projects to be economically financed. So here we are referring to the best that can be achieved, subject to the constraint that the project can be financed.

Traders have sought to argue to us that PTRs would be preferable for many market participants, because it avoids credit control requirements, and access to physical offers a sounder basis for market intermediaries to trade. But this conflicts with the general observation that trade in financial rights is generally cheaper than trade in physical rights, and there is already a credit control issue in relation to balancing charges. Trade in PTRs is less transparent, and would thus offer greater a profit opportunity for traders, without enhancing market efficiency any more (and, as we have argued elsewhere, in practice rather less) than would be achieved by issuing FTRs instead. If the complaint is that credit control requirements are unnecessarily onerous for electricity markets, that is a separate complaint that should be addressed, and not evaded through a change in the nominal form of the right without any real change in the underlying credit control problems.

4.2.2 Options and Obligations

Our target recommendation is that the TSOs must issue FTR as Obligations. TSOs should also be free to sell FTRs as Options, but only if technically and economically feasible, and not to the exclusion of selling rights as Obligations. We would note that even if the TSO were only issuing Obligations, there is nothing to prevent traders and financial institutions from issuing such options if there is a market demand. The main argument for prioritising the sale of Obligations is that only Obligations facilitate netting, and thus facilitate a greater range of trading opportunities, improving the integration of the market. Another significant advantage of FTR Obligations is that they are decomposable and can be chained – i.e. an FTR Obligation from A to B plus an FTR obligation from B to C is equivalent to an FTR Obligation from A to C, and also to an alternative route via D. This increases the range of hedging opportunities and increases market liquidity.

As noted, there is nothing to prevent, in a market where the TSO issues Obligations, market intermediaries offering one-sided CfDs equivalent to FTR Options if there is demand from customers. TSO-issued Options do have some advantages over Obligations for some customers, such as reduced need for credit control, but this typically comes at the cost of a much higher price for the Option in comparison to the comparable Obligation. This is the likely reason why FTR Obligations have been much preferred over Options by customers in the USA. We note that the FTRs offered on the Spain-Portugal border are Obligations, and also that certain markets in the USA started with Obligations only, indicating that this tends to be the form of FTR it is most natural for the TSO to offer it offers only one.

The argument for the TSO offering both Obligations and Options if possible, is that the TSOs should aim to maximise the value of the transmission system for market participants, and this is achieved by allowing parties to make their own commercial decisions by providing them a full range of network access products, backed up by the physical capacity of the network. Of course this can be complemented by financial CfDs if such markets develop.

The FTRs should be auctioned in periodic auctions subject to the Simultaneous Feasibility Test and NTC calculations. Auctions should be single price auctions, in which all purchasers of the same right pay the same price. Algorithms for solving such auctions are well known. Where there is a mixed auction for Options and Obligations, a much more complex algorithm is needed to solve which bids maximise the value of the auction, again with one single price for an obligation, and a different price for the option, the difference representing the value of the exercise right. Such an algorithm has been developed and is in operation in the USA. Whilst in the US, the extra cost of designing and implementing this more complex algorithm was considerable, we would expect that, now being understood, the cost of implementation would be modest for future implementations. The US found after the event that the demand for options was fairly modest, but what will happen in Europe is less clear, and if the implementation costs are low it is worth pursuing.

We would anticipate that FTR-based system would generally begin with FTR Obligations only, and later assess the desirability of issuing Options, given evidence of both a market demand and a market failure to supply them by intermediaries. It also makes sense to wait until markets have matured to demonstrate liquidity and reliable price formation before introducing Options.

Our recommendation to require that rights be made available as obligations can be seen as in some sense the most important recommendation of this report. It is the property of the rights being sold as obligations that facilitates netting, and hence enables trade back-and-forth across borders, in the same manner as back-and-forth trade exists within zonal markets whose internal transmission is considered sufficiently strong that congestion can be ignored. Integrating the market across borders demands that such back-and-forth trade be facilitated.

4.2.3 Duration of Rights

Our recommendation is that the duration of rights should match the preferred tenor of energy contracts, which is likely to be for at least three years ahead. This would require calculating NTC values well ahead of real time, which might be problematic. The NTC calculation methodology involves making assumptions on the state of the transmission grid and calculating Reference Flows, which depend on market conditions and feed-ins of intermittent generation. This implies that the longer the duration of the TRs the more conservative the NTC values for the auction will be, but as it is unlikely to be desirable to auction them all for the longest term, a large share of the conservative NTC three years ahead should allow more to be released shorter term. In addition, as has been the case in PJM, there is potential for a significant amount of transmission rights to be auctioned with multiple years' duration even with zero or low values for the conservatively estimated forward NTC. This, however, is only possible with FTR obligations than can be netted. At later times, as matters become clearer, the NTC calculation may indicate issuing additional rights. It is important that market participants are well-informed on the likely ultimate availability of rights, as this will affect their value. One issue that was revealed by the Texas example is that changes in the market design (e.g. from zonal to nodal pricing) may have to be delayed for the duration of the longest extant FTRs, unless these are bought back.

4.2.4 Secondary Markets and OTC

Secondary and OTC markets for transmission rights are important for the efficient operation of the market in those rights, so as to increase liquidity and enhance price discovery. Market participants that wish to trade FTRs between similar zones or hubs should be enabled to trade their transmission rights bilaterally. Zonal market designs should be significantly more liquid than nodal: for node-to-node FTRs, secondary trading and re-configuration of transmission rights would require a centrally administered auction process.

We further recommend that periodic reconfiguration auctions are held, perhaps quarterly and monthly, as this should enhance the trades across interconnectors. In the EC, reconfiguration auctions will typically be auctions that sell additional ATC as further rights become available, as certainty increases. But it might from time to time be a buy-back of rights if ATC reduces, if outages or planned maintenance are noted. We have noted earlier in the report that there are theoretical advantages in the decentralised trading of Flow-Gate Rights, as opposed to FTRs. But given the basis for the Target Model, that theoretical advantage is not so important in relation to the zonal market design.

4.2.5 *Volume of Rights, Revenue Adequacy and TSO Incentives*

Given the limitations of the Target Model market design, it is impossible to prescribe a specific percentage of the physical capacity of the interconnectors for auctioning of long-term transmission rights. Since the NTC depends on the assumptions for Reference Flow calculation the auctioned volume in different timescales should reflect the materiality of these assumptions. We however point out that by auctioning FTR obligations the volume of the auctioned rights can be maximised given the NTC constraints. In particular, we recommend that TSOs are compensated, through their regulated revenue, the full financial cost due of any potential discrepancies between the assumed Reference Flows and actual flows due to intra-zonal trades. There are possibilities that the regulation of TSOs can be devised to encourage them to maximise the availability of the physical capacity of the grid, but in general this would be a matter for national regulators. In general, it is important that arrangements devised by national regulators should not discriminate in favour of intra-zonal customers, and interconnection customers should in general enjoy the same level of rights as intra-zonal customers.

4.2.6 *Firmness of Rights and Force Majeure*

Following our analysis in Section 3.8, it is our recommendation that all rights auctioned by TSOs, with the exception of sub-sea links and merchant links, are 100% financially firm. This is not to deny the possibility of *force majeure* clauses applying, but they should be limited to truly exceptional circumstances rather than the day-to day fluctuations of an electricity grid with intermittent generation and typical temporary outages. The financial arrangements that apply to TSOs are a matter for national regulators, and matters such as the management of capacity availability and *force majeure* arrangements that TSOs can apply to their customers falls within that. But it is important that the arrangements in relation to interconnection customers should be the same as for intra-zonal customers. If TSOs can discriminate in favour of intra-zonal customers, as would appear often currently happens, this will be an impediment to market integration.

We bring to the attention of the commission that allocating the costs of revenue adequacy is a complicated topic which should be further analysed and falls within the general topic of inter-TSO compensation.

In the case of sub-sea links the technical characteristics of these assets differ significantly from terrestrial links. In particular, the power flows are controllable implying that the NTC will not be market condition dependent. On the other hand, the repair times are significantly longer reaching up to several months compared to a few days for terrestrial links. This implies that offering the same level of firmness for technically different assets might not be the most efficient solution.

In particular, an auction of transmission rights, subject to a Simultaneous Feasibility Test (SFT), could be devised that would offer rights of various firmness. Market participants could bid different prices and TSOs offer different volumes for varying degrees of firmness. The SFT would ensure the TSO revenue adequacy as well as maximise the value of the transmission assets to users. However, it must be pointed out that such a formulation of an auction and SFT of TRs with varying firmness has not yet been developed.

Another option would be to move to a system of FGRs, where the firmness of each FGR would reflect the technology characteristics of the specific asset. Since FGR auctioning and secondary trading does not require an SFT such an approach could be easily implemented but would carry all the disadvantages of the FGRs, as analysed in Section 3.2.

Another option could be to guarantee 100% the financial firmness of all the TRs on regulated links and deal with revenue adequacy and risk of asset availability through the performance base regulation of TSOs in the same way as terrestrial links. The availability clauses could be adjusted to reflect the technical reality of the assets. Such an approach would in essence socialise the financial losses of non-firmness leading to potential market distortions.

New under-sea merchant links might be encouraged to offer some kind of choice to their customers, semi-firm transmission, as currently offered, or fully firm at a price that includes, in effect, an insurance premium, possibly to be offered by the TSO from regulated revenues. It may turn out that the price of fully firm transmission is beyond what anyone would pay. The spirit of merchant investment suggests, however, that the degree of firmness offered should be left to the commercial choice of the investors unless compensated for by the regulator. But we would expect that all links become fully firm day-ahead.

5. IMPLEMENTATION ISSUES

5.1 PRECONDITIONS FOR IMPLEMENTATION OF FTRS

Our "target recommendation" only applies entirely where markets are coupled in accordance with the Target Model. Only in such a case will there be suitably reliable reference prices in each zone to allow a zone-to-zone FTR to be defined. This in turn depends upon there being an assigned auctioneer to carry out the market coupling. It appears to us that where markets are coupled then capacity allocation for FTRs can be implemented. This is demonstrated because it has already been implemented in the Spain-Portugal market, though probably not in a way consistent with the level of capacity or firmness we believe should be offered. So where markets are coupled, as they should eventually be through the Target Model, there are few other preconditions to the implementation of FTRs.

FTRs can facilitate zone-to-zone trading without the requirement to explicitly specify the interconnectors that may be involved, while PTRs are defined as rights for trade over a specific interconnector. Given this fundamental advantage of FTRs over PTRs, we recommend that the Target Model should facilitate long-term auctions of zone-to-zone FTRs. The implementation of such auctions, subject to the simultaneous feasibility test, is straightforward and conceptually identical to the day-ahead flow based market coupling process. The only significant difference would be the NTC calculation, which would be based upon a process of maximising the auction revenue rather than minimising the market dispatch cost, as happens in day-ahead market coupling).

5.2 INSTITUTIONS FOR USE OF FTRS TO EXPORT POWER

The operation of market coupling arrangements pre-supposes the existence of power exchanges to implement the market coupling auctions. One way that a generator can secure the financial benefits of export is to contract with an overseas customer, transact in the power exchanges (PXs) on either side of the interconnector, and purchase matching FTRs. This PXs anonymises the electricity itself, and indeed the generator may not even run when he is out of merit, although in this case the generator will be able to buy electricity for his customer more cheaply than he could have generated it himself. But the financial effect is the same as exporting, and the generator is hedged in the case that he does not run. But a possible disadvantage of this approach is that PX fees will be incurred in both countries, which potentially increases the transaction costs and reduces the gains of trade. This may be worthwhile if the overall effect is to improve the efficiency of the market in excess of the PX fees.

But this might be criticised as forcing market participants to make transactions with monopolists, the delegated market coupling auctioneers, which they can currently avoid. At present, a generator can make a contract with a buyer in another country and secure a PTR for the interconnector to that country. Provided he nominates the PTR, and presumably also submits a Final Physical Notification to the local System Operator of the intention to generate to meet the export booked, and the buyer, if required, submits his contract to purchase over that interconnector to his local SO, then neither party needs to transact on any power exchange (PX) and hence neither has to pay fees to any PX. On the other hand, those who choose to exercise their PTRs financially, by allowing them to be sold under UIOSI arrangements, likely pay some transaction cost, which may be comparable to coupling charges in future.

We believe it would be possible to allow by-pass of the PXs under market coupling with FTRs, so users can carry on avoiding PX charges if they choose, as they do currently. One simple solution would be for the parties to the contract to submit extreme bids and offers into the coupling auction – thus the generator would offer his contracted load at zero price, and the buyer (or the generator acting for the buyer) would bid in at the maximum allowed price for the same amount, leaving the auction to determine the prices in each market and hence the price difference to be settled – which would be exactly covered by the FTR. Since there would be no use of price discovery other than for settling the FTR, there would or should be no charge for using the PX in this manner. But this would have to be a right externally imposed upon the PX; in return for the right to operate the auction they would have to facilitate this process of by-pass at no cost to the parties.

If, however, the two parties were to bid economically, so that the generator offered in at his short-run marginal cost, and the buyer bid at the maximum price the power was worth to that buyer, then each would be able to reconsider their original contract and effectively find a cheaper solution to the delivery of and consumption of that power. Arguably in that case they were making use of the PX and would be liable for any charge.

More generally, as the simultaneous market coupling auction is a natural monopoly, it should clearly be regulated and effectively would offer its services (price determination, capacity allocation and settlement) at cost-reflective prices. Transactions that do not make direct use of (some of) these services would not pay the relevant charges, and commercial transactions (e.g. forwards, OTC and CfDs) would pay whatever fees the providers charged.

5.3 General Transitional Arrangements

It is likely that, immediately on implementation of these arrangements, liquidity would initially be low, and hence price formation would initially be weak. This would offer opportunities to market intermediaries to profit at the expense of the industry. These opportunities should reduce as the market matures. Although in the long term it would be desirable that the full ATC should be sold as early as possible, this becomes less desirable if price formation is weak.

We would therefore recommend that initially only a relatively modest proportion of ATC is released to the market at the earliest point, but instead to release it to the market in batches. Once liquidity in markets is established, then a higher proportion of ATC can be released earlier. The timing of this might vary by market.

Similarly, it would be appropriate to have auctions at which additional ATC is released to the market, or reconfiguration auctions, relatively infrequently to start with, in order to concentrate the scarce liquidity.

For the same reason, it makes sense to start by selling FTR obligations only to start with. Options, being harder to value, in general having markets of lower liquidity. Thus there is a higher possibility of them being mispriced until price formation has improved.

5.4 Transitional Arrangements Where Long Term Contracts are Already in Place

Market participants may have made long term contracts predicated on the continuation of present arrangements, and by introducing new arrangements, this may disturb those arrangements. Arguably one could say that this is a contractual matter between the parties, and they should have provided for changes to institutional arrangements within their contracts, since the indefinite continuation of present institutional arrangements can never be relied upon. Moreover, especially when it is public knowledge that EC has been seeking to change institutional arrangements for a long time. Nevertheless transitional arrangements need to be considered to move to new methods without undesirable side-effects.

There are two issues to address – the co-existence of CfDs, PTRs and FTRs, which seems unproblematic, despite the injunction in the Framework Guidelines that both PTRs and FTRs should not exist on the same border. The TSOs will set a date for which transmission arrangements will be FTRs rather than PTRs, beyond the date of outstanding PTR rights, and there will be a PTR market in dates up to that date. Since we have been told that TSOs do not currently issue very long-dated PTRs, the risk of there being outstanding long-dated PTRs does not seem to exist, and transition would likely take about a year at most.

The market will decide between CfDs and FTRs, with the main risk being one of diluting liquidity. The evidence from competition between futures exchanges is that liquidity drains away into the preferred hub, and again the problem ceases to exist by market forces. The harder problem is where zonal boundaries change, possibly down to the nodal level. In Texas, the transition took 3 years (the duration of the longest contract) to manage. It might be possible for the central auction office to compute the zonal prices for virtual zones at the day-ahead stage to facilitate any transitional contracts, or it might just require a lengthy period before such changes can be made (but the possibility that the costs of redispatch become too high rapidly to sustain unsuitable zones should be anticipated).

There may be an additional question where the underlying power exchange product changes, as for example in the UK with the transition from a pool with capacity payments to an energy-only market (NETA). That might be handled by separating out the two so that the coupled market only determines the system marginal price (=cost) with local generators receiving capacity payments, although the legality of denying capacity payments to generators located across the border but selling into the market will need scrutiny but the US experience has demonstrated the importance of defining capacity payment eligibility in terms of the ability to deliver reliably into the relevant market. As a general rule, any FTR will have to be very clear about what the relevant price should be in the event of market design changes, particularly those caused by creating different price zones.

5.5 Arrangements in Markets not Coupled According to the Target Model

Where markets are not yet coupled according to the Target Model, FTRs usually cannot be implemented. The logical approach is to allow non-coupled markets to continue to offer existing PTRs in their capacity auctions, which will migrate to UIOSI when the markets are coupled, at which point they can gradually (as they mature) be replaced with FTRs as part of the process of market coupling. If the date of coupling is predictable, then forward FTRs can be issued ahead of this date for exercise after.

It would be desirable to explore the options for evolving from the current Tight Volume Coupling between CWE and Nord Pool to a price coupling arrangement with FTRs, and thereby facilitate trades between the two markets. Given the zone-to-zone definition of FTRs TSOs could auction FTRs between the Nordic Zones (or for that matter any price zone within the Single Electricity Market) and a virtual hub, in which area price would correspond to the Nordic System Reference Price in order to maintain the liquidity of this market and consistency with the Nordic CfD definitions.

5.6 MITIGATION OF INCIDENCE EFFECTS

The introduction of more transparency and trade in commodity markets tends to result in price differences being arbitraged away, with remaining price differences between markets being limited to the cost of transport from one to another. In final user markets, there can also be variations in price due to strictly local costs such as distribution, retailing and other local transaction costs. Whilst total economic benefit rises when markets are integrated, some market players can now face higher prices than before, because the low-cost providers in their region may now more easily export, providing external competition for supply which competes the local price upwards. This does, however, provide increased income to exporters in the region and possibly higher congestion revenues. In the case of electricity, increased transparency might also affect transmission costs, meaning that some customers who previously benefited from transmission price equalisation may no longer do so, and might have to pay more to reflect the congestion on wires in their area. Moreover, increased opportunities for trade in electricity might congest wires that were not previously so congested.

In many markets, similar changes are seen as inevitable effects of globalisation, and the overall economic advantage of trade in all markets is seen as advantageous, even if prices go up in a few markets. But in the case of a commodity as essential to life as energy, there is likely to be particular attention to local price increases, and there can be valid social reasons for protecting the position of some consumers.

FTRs provide an income stream which individual member states can divert to groups of customers if they choose, whether to protect them from incidence effects, or else for reasons of social policy. This happens in some US markets, explicitly by allocating directly the FTRs themselves to load serving entities, who can then trade them, or simply earn the revenue from them. This is also justified on the grounds that the transmission networks have been financed from the money provided by customers in regulated energy markets, and thus they should benefit from the profit generated. In principle, income from FTRs should be adequate for any incidence effects from trade.

Incidence effects can occur when cross-border flows for a region amount to a substantial transit across that region. In effect, the local market may be bearing the cost of that transmission network, but others out of region are benefiting from its existence. This might result in reluctance of a region to interconnect to other regions as it would see little of the benefit. The existence of FTR rights, which might be allocated to certain parties seen as losing from a deal, can be used to compensate for this additional cost.

But the main issue that will likely prove contentious in generating further incidence effects, is external (CEC) pressure to create more price zones to mitigate the temptation to export congestion, as happened in the case of Sweden in relation to its exports to Denmark. A significant reason for the available NTC of a link falling short of its physical capacity can be congestion within the network beyond it, in a region treated as a single price zone. This will result in pressure to divide into more zones, with resulting incidence effects. Some sweetening of the pill is again possible here by allocating FTRs to certain parties. This is a matter for subsidiarity. The situation should also lead to pressure on TSOs to reinforce their internal networks if this internal congestion is significant.

5.7 OTHER REGULATORY ISSUES

5.7.1 *Tolerance for Slow Harmonisation of Regulatory Details of Markets*

There are a number of differences between regulatory arrangements in different member states in the EC, which can have the effect of reducing the effectiveness of market coupling between markets. FTRs depend upon robust references prices being established for each zone pair for which FTRs are issued. Coupled markets necessarily produce these reference prices in order to function. But regulatory differences between coupled markets can have the effect of reducing the liquidity of the reference prices, and hence reduce the reliability of their price formation.

These differences include difference in gate closure rules, differences in loss recognition, presence or absence of capacity payment mechanisms, etc. But this should not be an impediment to the implementation of coupled markets and FTRs. Markets have been coupled without such harmonisation, and this should continue. Rather, the fact of proceeding with market coupling, and implementation of transmission rights as FTRs will produce greater transparency of the effect of these non-harmonised features of markets. This will make clearer the reasons for remaining market problems, and thus produce greater pressure and focus towards harmonisation of remaining factors on member states from market participants.

5.7.2 *Issues related to Renewables: Transparency of Subsidy, ATC, Revenue Consequences of Forecasting Errors*

A problem increasingly faced by TSOs is that wind in any future hour is hard to predict and, assuming it takes priority in dispatch (either legally or because it can undercut any other generator), the remaining NTC is unpredictable until a few hours ahead of time. Thus it happened one weekend in February 2011 that unusually high wind in Germany, generating 20GW rather than 5 GW the previous year, forced TenneT as the relevant TSO to block commercial cross-border flows in CWE,[71] and remove almost all the ATC of 2 GW between the Netherlands and Germany to retain security margins. Such events are likely to become increasingly frequent, and raises the question of whether they would greatly reduce the willingness of TSOs to release adequate volumes of long-term FTRs.

For conventional generation trading across borders wind creates no (financial) problems. Consider the case in which a generator D in Germany sells to a company N in the Netherlands and holds an FTR on Germany-Netherlands. If wind displaces the DE-NL trade, then D is compensated by the fall in price in Germany and the rise in price in Netherlands, and D can sell in Germany while N can buy in Netherlands and their revenues and payments remain as before. The TSO will pay-out the now higher price difference across the interconnector. The key question is whether the TSO will receive the price difference from the extra wind that has flowed.

[71] *Argus* Power Europe *17/2/11*

That raises the question about the contracts held by wind and whether they or someone else pays for the extra costs of exporting the surplus power in the region. Suppose, as seems relevant in North Germany and Denmark, that the wind farms have effectively firm access and hold rights to earn at high Feed-In Tariffs (FITs) with a fixed price, f. They receive f/MWh regardless of their zonal price. The counterparty to the FITs (some agency who has the authority to recover the subsidies from charges to final consumers) should receive the zonal price in the zone in which the wind is located, and pay the FIT price, recovering the difference from consumers. If the interconnector would have been constrained in any event, the zonal price in the importing zone will be unaffected, and there are no external repercussions. If the interconnector would normally be unconstrained, but wind now causes it to be constrained, supply into the import region will have increased, and the price there will have fallen, with a net gain to that zone: generators exposed to the spot price will receive less, exactly equal to the gain of the consumers these generators supply, and in addition consumers can consume a little more at a lower price than they expected.

The issue thus resolves into whether the counter-party to the wind FIT needs to hedge with FTRs, or whether it will self-insure, in effect passing on the cost of the subsidy (equal to the FIT price less the spot price) to consumers, or whoever is providing the revenue stream for the renewables subsidy. A deeper question is whether the *de facto* arrangement is one in which the TSO has the power to constrain off other flows and not compensate the holders of FTRs, as part of a mechanism for concealing the true cost of the public support to renewable energy.

We would argue that, for the purposes of long-term contracting for interconnectors, the counterparties to renewables contracts should be liable for the financial consequences of wind flows across borders, effectively offering into the cross-border auctions the predicted wind flows day ahead (presumably at zero price to ensure success), with adjustments intra-day.

So, in sharp contrast to the case of a failure on the interconnector, the TSO issuing FTRs and collecting the cross border price difference is left intact in the presence of unpredictable wind. However, there might be a remaining concern if the TSO feels the need to set aside a larger fraction of the interconnector for security in the presence of greater wind volatility, in which case the TSO has in effect possibly oversold the ATC. This should not happen if the FTRs must satisfy the short-term feasibility constraints, but it might reduce the amount of ATC that can be reliably offered to the FTR long-term auction.

TSOs are likely to be reluctant to expose themselves to potentially large commercial risks, and they are likely to respond by reducing the ATC that can be forward contracted, and/or limiting the duration of any contracts to a year or less, despite the willingness of buyers and sellers to contract for longer periods. Assuming that it would be desirable to facilitate cross-border trade and to encourage the release of as much capacity as possible, and indeed to provide incentives for building additional profitable capacity, how should these risks best be borne?

One possible solution is to allow TSOs to use the revenue from zonal price differences to compensate for forecasting errors. In effect the TSO sells M MW of capacity in an FTR auction ahead of time, and then finds the need to buy back B MW for short-term balancing actions. These might be netted off the auction revenue, on the argument that although they could be deemed to be balancing actions to be charged to wind, with FITs these are effectively passed back to consumers, who would have been the beneficiary of the auction revenues anyway.

5.8 CREDITWORTHINESS AND OTHER FINANCIAL REGULATORY ISSUES

5.8.1 *Regulation under MiFID*

Directive 2004/39/EC on markets in financial instruments, commonly known as MiFID, sets out to harmonise regulation of investment firms and regulated markets. It was supplemented by Directive 2006/73/EC, on the implementing of MiFID, which sets out details of rules. Further implementation requirements were set out in Regulation 1287/2006. Whilst the Regulation applies as law directly in member states, the Directives are transposed into legislation by each member states in their own way, so that there remains the possibility of distinctive regimes from country to country, within the scope of the requirements set out in the directives. The EC recently carried out a consultation on further legislation to amend MiFID, and draft legislation is expected to be published this year.

MiFID in general intends that financial derivatives of commodities should be seen as investments coming under the scope of the MiFID regime, but that the commodities themselves should not be.[72] The dividing line between the commodities themselves and financial derivatives on such commodities is not a clear one. If FTRs – or indeed PTRs – were to come under the scope of MiFID, then this would require TSOs issuing such FTRs to submit themselves to a range of regulation suitable for firms marketing financial instruments.

MiFID also provides that companies whose financial activities are ancillary to their main activities are not financial companies, and hence not regulated under MiFID. A company whose FTR position is at most as large as its physical position might sensibly therefore be regarded as ancillary. That should certainly exclude the customers for FTRs – eg, the generators or electricity purchasers – from being regulated as financial companies under MiFID. In the case of the TSOs themselves, who might be netting FTR obligations, and thus have a total volume of FTRs larger than their physical position. But their net position would be no larger than their physical position, and a sensible interpretation would be that the FTRs are ancillary. But ultimately it would be for the EC to decide whether that was the case or not, and issue an authoritative clarification.

We are recommending in this report that FTRs should be the sole instrument by which TSOs give access to use of cross-border transmission capacity. The FTRs would be issued by the TSO at auction. The quantity issued would be related to, although for complex reasons related to ATC, not exactly matched to, the physical capacity available. There might be subsequent trading of those FTRs, for example on an exchange, which might be a regulated exchange, not mediated directly by the TSO. So although the FTR would be similar in operation to a CfD issued by true investment firm, which would clearly be a derivative, the FTR issued by the TSO would be the commodity itself. A TSO-issued FTR, backed by capacity, may also have distinctive detailed terms which would distinguish it from a purely financial CfD with the same headline financial terms issued by a financial intermediary.

We believe that the arrangements we are recommending specifically in relation to FTRs would be more appropriate to them as regulatory arrangements than more general regulatory arrangements applying to investments. The quantity issued would be subject to

[72] *See Para 22 of the preamble to Regulation 1287/2006, which states that as an intention.*

rules related to the physical network capacity. The FTRs would have the possibility of *force majeure* in relation to actual happenings on the network. There would be careful attention to the revenue adequacy of the TSO to meet its obligations, and the possibility of sharing losses with other customers through the regulatory compact, whereas CfDs issued by financial intermediaries would be priced on actuarial principles. These characteristics clearly distinguish FTRs issued by TSOs from general financial derivatives.

We shall further see below that the characteristics of an FTR do lend themselves to needing credit risk management and clearing arrangements. So the owner of an FTR would need some relationship with a body fit to carry out these activities, but this does not need to be the TSO. This further weakens the requirement for TSOs, as issuers of FTRs, to be regulated under MiFID, if there are separate clearing arrangements to ensure creditworthiness of parties who might have to pay up at time of settling the FTR. But this is not to say that they may not choose to carry out these financial activities themselves.

5.8.2 Credit Management

There is counter-party risk in relation to FTRs. FTRs can be out-of-the-money, and therefore the counterparties need to be identifiable and good for settlement. A customer buying FTRs to match their own business requirements would be naturally hedged. Nonetheless such a customer might have problems in their business and find themselves holding an out-of-the-money FTR when they are no longer in a position to exploit the favourable market position that is usually present when your hedge becomes out-of-the-money. Others might buy FTRs as intermediaries to trade them, and would not be naturally hedged. FTRs expected to be out-of-the-money would in principle have a negative price, and there can be particular credit risk in such cases, especially if the income from the negative price is available up front. But FTRs expected to be in-the-money can also turn out to be out-of-the money from time to time due to random fluctuations. Thus there are reasons to suppose that even a counterparty buying FTRs to match its business requirements might have difficulty settling on the day. There have been a small number of significant cases of holders of out-of-the-money FTRs being unable to pay in the USA, which has resulted in greater amount of care being taken in relation to this issue there.

For these reasons, there would need to be arrangements to manage counterparty credit risk with FTRs. A TSO might well decide that counterparty credit management is not a business it wishes to be in, and therefore they would look for external provision of this service, for example to a clearing house. Management of credit risk might require FTR holders to provide collateral of increasing amounts as the risk of their FTR being out-of-the-money increases, as for example happens on commodity exchanges.

Owners of FTRs who are naturally hedged will no doubt feel that credit control arrangements are unnecessary for them, and prejudicial to their cash-flow. Nevertheless, as noted above, this does not necessarily mean that they present no risk at all. Similar issues exist in relation to hedging in other commodity markets, and it is routine to make arrangements for it. We have also noted in Chapter 3 that credit management of FTRs would not be essentially different to whatever credit management is currently needed for CfDs on Nord Pool, to the extent these are two-sided. Market participants who do not want to subject themselves to credit risk control can buy one-sided instruments. Even if these are not available from TSOs, they should be available from financial intermediaries. But one-sided instruments are likely to be significantly more expensive than pure FTRs, precisely because of the actuarial cost of removing the downside and the lower liquidity of options.

Precisely one of the advantages of FTRs is that TSOs would not have to keep track of their owners for the purpose of nomination. Owners of in-the-money FTRs would no doubt present their rights for collection. But the TSO would need to be able to collect on out-of-the-money FTRs, which in principle could be any right issued. Thus some registration would be required, even if the time pressure of nomination would not be critical. Together with the point on credit management, these jointly point towards the likely need for TSOs to make clearing arrangements.

In effect, an owner of FTRs would need a relationship with a someone who manages the credit risk and provides for collecting any monies owned from that owner at the time the FTR applies. Such a person is likely to be regulated under MiFID, but this does not need to be the TSO. We do not see a strong argument for specifying arrangements here, rather the TSOs can devise their own appropriate arrangements.

We would note that there is already a requirement for some degree of credit control in electricity transmission, because a PTR becomes an obligation once nominated. A generator that fails to generate according to its nomination becomes liable for charges under the balancing system, and some security would be appropriate in such a case.

6. RECOMMENDATIONS FOR FURTHER STUDIES

We would recommend that the Commission may wish to consider the following issues in future studies:

- Allocating the costs of revenue adequacy. This is a complicated topic which should be further analysed and falls within the general topic of inter-TSO compensation. There may be advantages in a common approach to this across the EU more quickly to integrate markets. However the lack of a common approach should not be used as a reason for delaying the implementation of the conclusions of this report.
- Allocation of cross border investment costs. The present approach of allocating cross-border network reinforcement costs frequently does not allocate them to those who most benefit from them. Consideration may be needed for methods of funding the costs of that infrastructure. Again, this impacts inter-TSO compensation.
- Integration of markets of different designs. Significant differences in market designs exist, eg, energy only and capacity markets, different balancing mechanisms, different market timings. The ability of generators to participate in capacity markets in different zones is likely to be contentious. We have recommended that different market designs should not be used as an impediment to proceeding with market coupling, and that market coupling itself may promote convergence. But further study is needed of the potential problems of coupled markets with different market designs, to assess whether there is damage if the hoped-for convergence does not occur, and whether market imperfections might propagate.
- Mandatory Power Exchange participation. Many electricity market designs mandate PX participation, at a cost to the participants. A market design based on the concept of bilateral trading is potentially inconsistent with mandatory PX participation. National regulators might evolve different approaches, and there may need to be consideration of what approaches should be permitted, or at least consideration of whether there should be required to be a method of trading bilaterally without participating in PXs.
- Zone definition. The Sweden/Denmark case has indicated the importance of zone definition in market coupling. Ideally zone definition should aim to maximise ATC while minimising the effects of market condition dependent reference flows. In some cases there may be strong local preferences for large zone size, and there may be grounds for promoting grid reinforcement if that would objectively justify the large zones. Further work is required here on how zones should be defined, and what principles the EC should require be adopted in designing zones.
- ATC under different security standards. Present network security standards may unduly restrict the amount of ATC offered to users. More generally the standard methodologies for declaring ATC should be studied, to prevent undue conservatism by TSOs.
- TSO incentives and governance. By governance, we mean acting under externally set rules, as opposed to making decisions. When TSOs are free to take

commercial decisions, they may respond to various financial and non-financial incentives, depending upon their corporate structure. Determining the corporate structure, and hence what incentives might apply, is probably an issue for national regulators. The extent to which certain things should be set out in rules, and who sets those rules and how they are revised, for example in relation to ATC, is potentially an issue of concern to the EC.

In general, it is possible to implement the conclusions of this report without coming to a final view on the above issues. These are matters that will improve the integration of the electricity market, and the efficiency of the market in transmission rights. But the fact that they are worthy of further study should not prevent the initiation of a long term market for cross-border transmission rights mediated by FTR Obligations.