INTERIM REPORT

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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 Štrbac (Imperial College, London) present this interim 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 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 chapter 4 of the report, where we present emerging conclusions for discussion, and identify the tasks still remaining).

Our interim report addresses the first two objectives. We were 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 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 which

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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.*

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 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.

Our analysis to date, which needs to be tested in further discussions with stakeholders, leads to a number of conclusions of varying degrees of robustness. We tentatively present six key conclusions at the present stage.

- 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. 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. Thus if the IFA has an NTC of 2 GW, the relevant TSOs could continue to issue FTRs until, for example, French traders, generators or suppliers held 10 GW of FR->GB FTRs[2] provided others held 8 GW of GB->FR FTRs. The potentially substantial volume of virtual trading could considerably increase the size of the contestable market in each country and hence intensify competition in each market. While it would be possible to create PTRs that were firm obligations, and to continue issuing and netting them with the same result, it is likely to be more cumbersome and costly than creating FTRs.

- 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 a second-best way of helping to finance a merchant interconnector. If that is considered the best practical way of enhancing interconnection, the fact that it

[2] A FR->GB FTR entitles the holder to receive the excess of the GB price over the FR price but to be liable for any excess of the FR price over the GB price, and conversely for a GB->FR FTR.

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).

- 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.

- TSOs should be required to issue FTRs 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). 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.

- 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.

FUTURE WORK

We will complete our round of interviews of stakeholders, and also present stakeholders with emerging conclusions for discussion. We will, if practical, achieve this in part by attending the next Florence Forum, and also by holding a workshop with invited guests, scheduled for 31 May 2011 in London. Implementation issues remain.

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 interim 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.

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. To date we have interviewed ENTSO-E and CEFIC. ERGEG is winding up, but we have interviewed CEER, closely related to ERGEG, instead, and we expect to make contact with ERGEG's replacement body ACER in future. We have exchanged clarificatory emails with ENTSO-E and EFET Arrangements are in train to make contact with the other stakeholders we are required to interview, EFET, Eurelectric and IFIEC.

This report indicates the progress we have made on the three objectives of the study. It demonstrates, we believe, that we have collected a considerable part of the information required to complete the study, and have made considerable progress with the first two objectives of the study. Gaps remain, and conclusions need to be firmed up and refined, which will be done in consultation with you and stakeholders, as indicated at the end of

Chapter 4. Practical recommendations, the third objective of the study, will follow from that.

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 some early conclusions on desirability.

Chapter 3 makes progress with the second objective of the study. It 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 briefly present emerging conclusions for discussion, and briefly present future work.

2. THE DESIRABILITY OF LONG-TERM TRADING

2.1 INTRODUCTION

This chapter sets out our progress in evaluating the advantages and disadvantages of tradable long-term rights for cross border electricity transmission capacity. It is not yet a complete argument, but we believe it is a suitable basis for further discussions with stakeholders and to move towards completion of the report.

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."

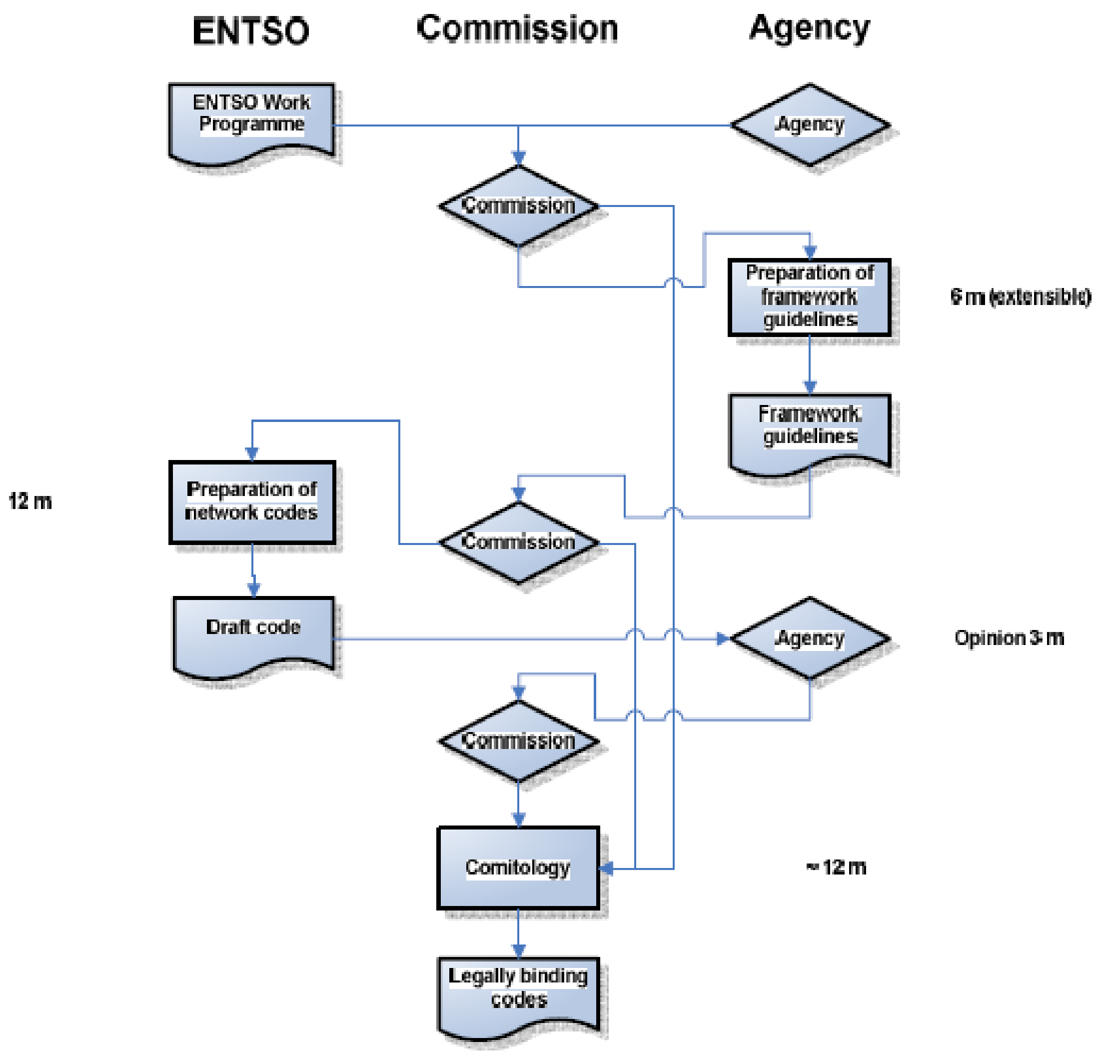
Under Article 7 of Regulation 713/2009, ACER has the power to decide on the terms and conditions for access to cross-border infrastructure. Under Article 8, ACER may decide that some aspects should lie within the competence of national authorities to be agreed bilaterally, save that ACER will take over 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)[3]



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

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.

- 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.[4]

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.

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.

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

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.

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 Electricity Model.

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. 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. 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.

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.

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 is relevant. This suggests a reformulation of this objective as follows.

Accommodates intermittent generation

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

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.

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.

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.[5] TSOs can and do bilaterally arrange to trade balancing services across interconnectors.

- The Target Model requires that TSOs would be obliged 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 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.

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[6] and on 23rd March 2011 ENTSO-E released a comprehensive draft of the requirements of the pilot Network Code as the result of the

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[5] *The Single Electricity Market in Ireland is one important exception as is MIBEL in the Iberian Peninsular, both of which have capacity payments*

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

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.[7]

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),[8] 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 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

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[7] *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*

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

capacity allocation and congestion management (CACM) to the EC. In the words of the web page:

> "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.
>
> "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 process of deciding how best to determine Net Transfer Capacity (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,[9] 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

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

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 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 present 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 contracting is 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 2.2 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

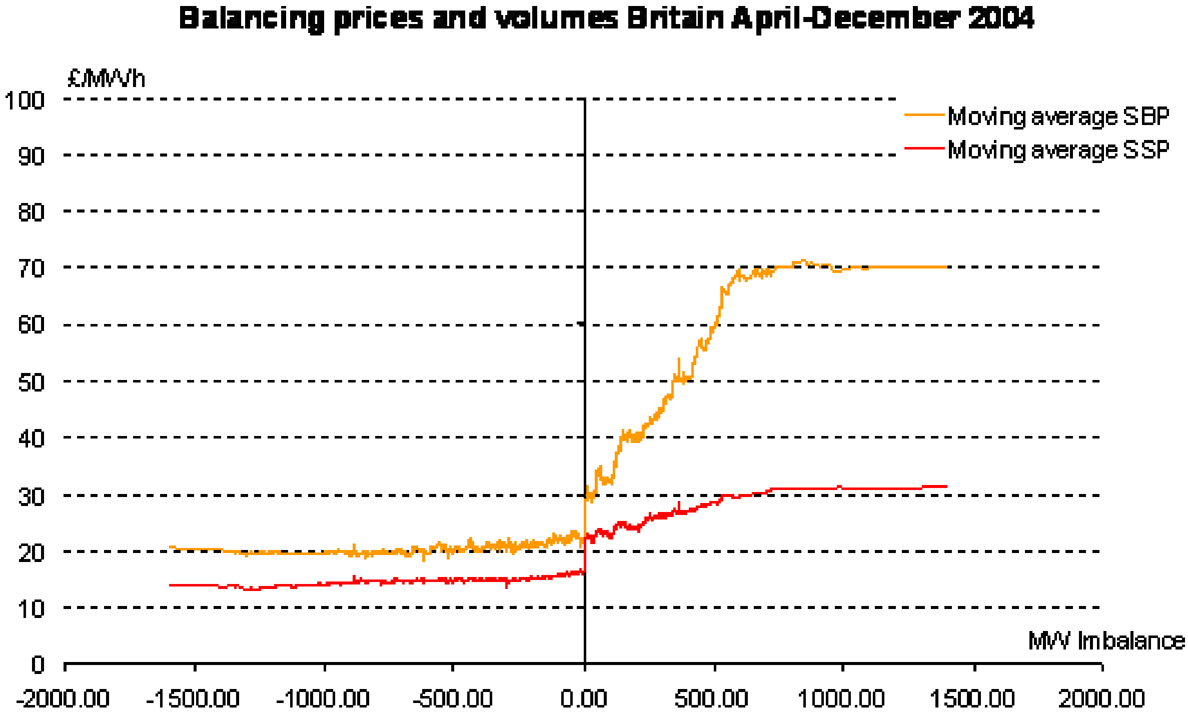
These standard bilateral contracts are traded on a power exchange or on an Over-the-Counter (OTC) market, and provide guide prices. These secondary markets provide an option for rebalancing portfolios. If a generator has sold M MW forward, and wishes to reduce this to B MW, then he could either renegotiate 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 2.2.

Figure 2.2: Bid-offer spread in the British Balancing Mechanism



Source: Elexon data

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[10] 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

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

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). 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.

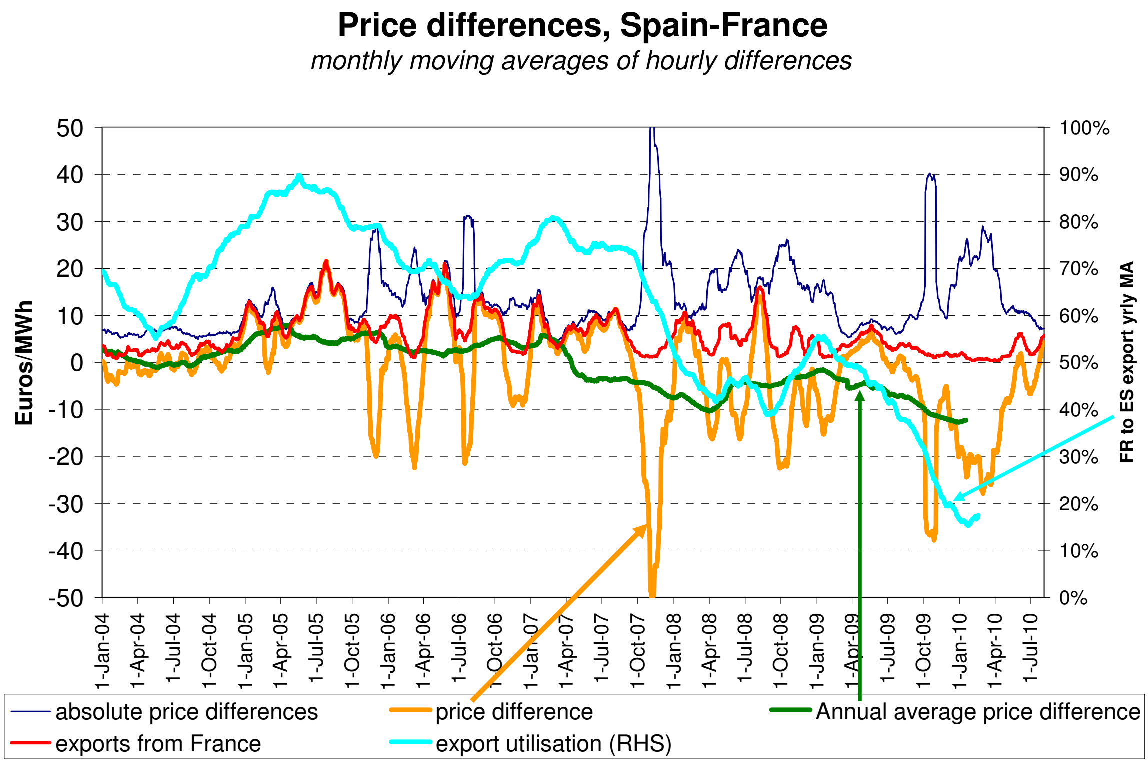
There are natural variants on this standard two-sided CfD. A one-sided CfD might set an upper price, u, in which case each accepts the wholesale price if it is below u, but otherwise the generator pays $p - u$ to the supplier. This caps the risk of price-spikes that the supplier might face.

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 2.3 below.

Figure 2.3: 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 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 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 (DA) 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 (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 DA coupled auction on 19 July 2006 at his marginal cost, say €30/MWh, after which the French DA daily average price clears at €116.83/MWh while the Spanish market clears at €55.30/MWh.[11] If the markets were for daily blocks then the Spanish company would be better off buying DA in Spain at €55.30/MWh, selling his French contract into the French DA 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.

In short, the Spanish company can act as an arbitrage trader in the Spanish and French DA 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

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

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 DA average price is €24.87/MWh and the Spanish price is €40.99/MWh. With a liquid DA 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 DA. 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 DA 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

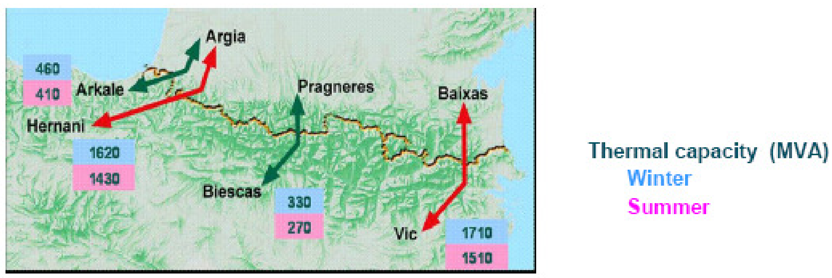
Suppose that the French and Spanish TSOs have set up a trading arm to auction off the IC and share the revenues according to some formula. Suppose that they have sold the 2006 France to Spain PTRs or one-sided FTRs at what emerges as an unattractive price – say €2/MWh instead of the actual arbitrage 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 DA 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 DA) 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 DA 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 2.4 (and both are far less than the thermal capacity).

Figure 2.4: 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 DA market on which they are struck provides a reliable reference price (as it surely would in a coupled DA auction). FTRs would also be simpler to clear through a clearing house[12] that agents holding contracts would surely require, ensuring credit worthiness (although standardised physical contracts can also be cleared, as happens with many OTC contracts in Nord Pool).

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 issue FTRs (e.g. trading houses in places like Morgan Stanley), taking speculative positions on the future price differences, and hence increasing market liquidity.

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 $\mathrm{E}p_E = g+c$, and as he is willing to sell at the bus bar at price 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 is 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 $g > \mathrm{E}p_E - \mathrm{E}p_S$.

[12] *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.*

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 Ep_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 Ep_E).

Now consider the same interconnector failure again, with initially Ep_E - Ep_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 desirable0.

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 2.2).

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 system of FTRs.

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).

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 make it harder to forecast ATC in advance. It raises important issues if NTCs are based on flow-gates, for a reduction in inter-zonal NTCs now reflects a change in the pattern of intra-zonal flows as a result of changing wind injections. On the assumption that the flow-gates have not changed, that must mean that there is internal congestion that should properly be handled either by internal re-dispatch, or by internal price splitting, if the internal congestion problems are not to be exported to the zonal boundaries (as was the case between Sweden and Denmark that lead to the DG Comp inquiry).

TSOs are likely to be reluctant to expose themselves to potentially large commercial risks that this kind of 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.

The more satisfactory solution is to address the heart of the problem, which is the unsatisfactory method of computing NTC ahead of time, and instead shift to flow-gate methods and recognise the need for internal re-dispatch rather than visiting such problems on those trading across borders.

2.6 EMERGING CONCLUSIONS ON DESIRABILITY

In this interim report, we have begun to sketch the important role that long-term transmission rights would 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 automatically allow for netting. Moreover, financial contracts are superior to physical contracts in encouraging liquidity, market transparency, clearing house credit assurances, and lower transaction costs. The remaining risk to address is that of the TSO overselling NTCs (either through a failure to re-dispatch to deal with internal constraints, or a failure of a transmission link). That risk is one best handled by the TSO(s) and should not be visited upon cross-border trading.

This interim report has not fully considered all the relevant matters in relation to all the objectives. In the later part of the study, we will be further considering how best to implement tradability of long-term transmission rights so as best obtain the objectives. In particular, some study is needed of the effect on actors with market power, and potential methods of facilitating investment.

But in general our early 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.

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	

Objective	Advantages	Disadvantages
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.
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.	TSOs are likely to be resistant to bearing additional risks, even if it is efficient and possible for them to do so.
Accommodates intermittent generation	Solutions exist for accommodating wind efficiently.	These solutions require providing more information and allocating more responsibility to supra-national dispatch.

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**[13] (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 for interzonal congestion hedging

For the purposes of this interim report, the aim of this chapter is primarily to present the analysis to understand the issues, and assemble the fact base as evidence. We do not at this stage present the detailed arguments needed to support specific conclusions. Some early 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

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

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 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 that 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. TSOs give the right 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 capacity is resold; in the case of an implicit auction this is equal to the day-ahead price differential between the two zones that the PTR links.

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. 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),[14] 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 electricity markets operate an implicit auction to decide which generators should despatch, as a result of which a market clearing price is established in that market. When two markets are linked by a market coupling process, if the interconnectors joining them are adequate to make any transfers required, the prices in

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

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 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 a financial product that is equivalent in value terms to having access to the interconnector. But it only works 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, with nodal pricing, would be at the point of injection or source) to another price zone (again, with nodal pricing at the point of withdrawal or sink) and is directional. A FTR is a purely 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, ie, if the price at the sink is lower than the source price then the option payout is zero. In this sense, FTR options are equivalent 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.

An FTR is a specific case of a general financial product known 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 known as a CfD, but which is in financially equivalent to a FTR. The significant difference is that for FTRs, and also PTRs, the underwriting parties are the TSOs, whereas for CfDs anyone can underwrite the contracts. Nord Pool CfDs are traded as futures in the NASDAQ OMX exchange. A financial institution issuing a CfD will take an actuarial view of the premium that should be charged, whereas a TSO in possession of the underlying physical right against which to hedge the issue of the financial rights should be in a position to offer better value.

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.[15] As a reference case to

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[15] *As should be the case in a two node interconnection under perfect competition and perfect foresight*

examine cross-border bilateral trading with PTRs, we will refer to the England-France interconnector.

Interconnexion France-Angleterre (IFA)[16] 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.[17]

To be able to use the interconnector, a user must go through a specific application process and be deemed eligible by the operators.[18] 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 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.[19]

- 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:

[16] *National Grid, 2009,"IFA User Guide and Capacity Management System FAQ"*
[17] *National Grid,2010, "Interconnexion France-Angleterre Performance Report 2009-2010"*
[18] *National Grid, 2009,"IFA Access Rules, Issue v. 7.0"*
[19] *National Grid, 2010, "IFA Long Term Auction Timetable 2011"*

- 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:

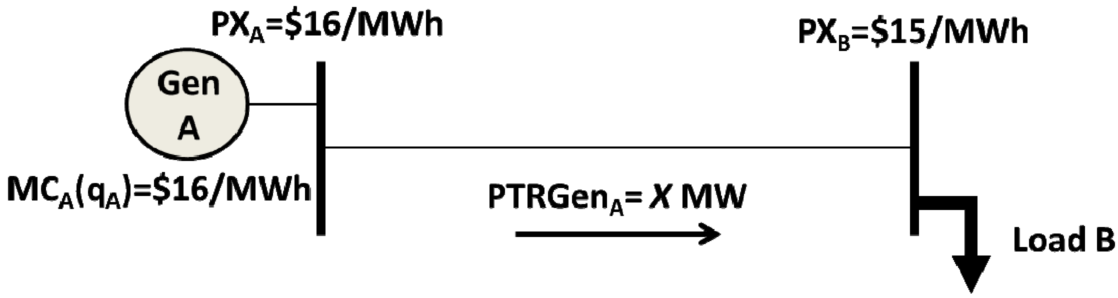
- The amount of capacity released in long-term auctions is typically fixed.
- The amount of capacity released in the day-ahead auction is again fixed but the Operators also include any unsold/unused long-term units and any extra capacity that can be made available through the netting of already submitted long-term nominations.
- 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 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 thier 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)[20] 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.

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 right owner is required to nominate thier 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

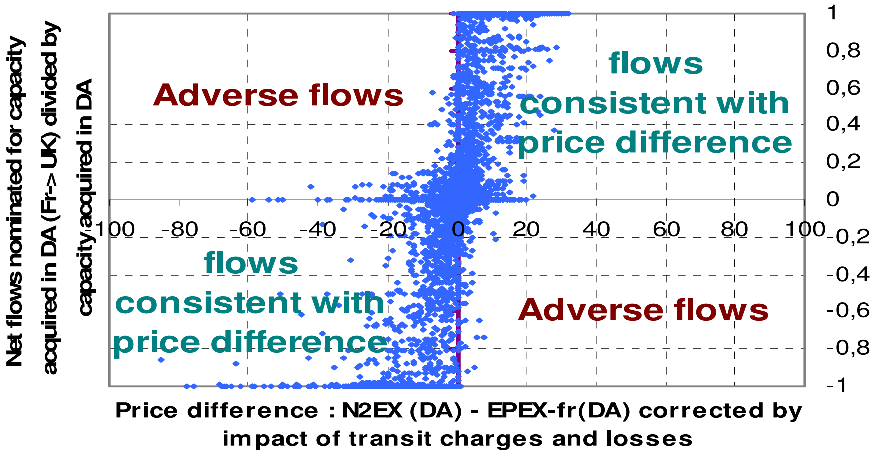
[20] *The generator would be indifferent between selling or not producing in their local PX given that the local PX price is equal to Gen A marginal cost.*

- 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 to 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[21] 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.[22]

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.[23]

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

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

[23] *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*

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 necessary 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.

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. This becomes a primary concern when 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 their decides to trade between any two countries by simply acquiring the associated FTRs.

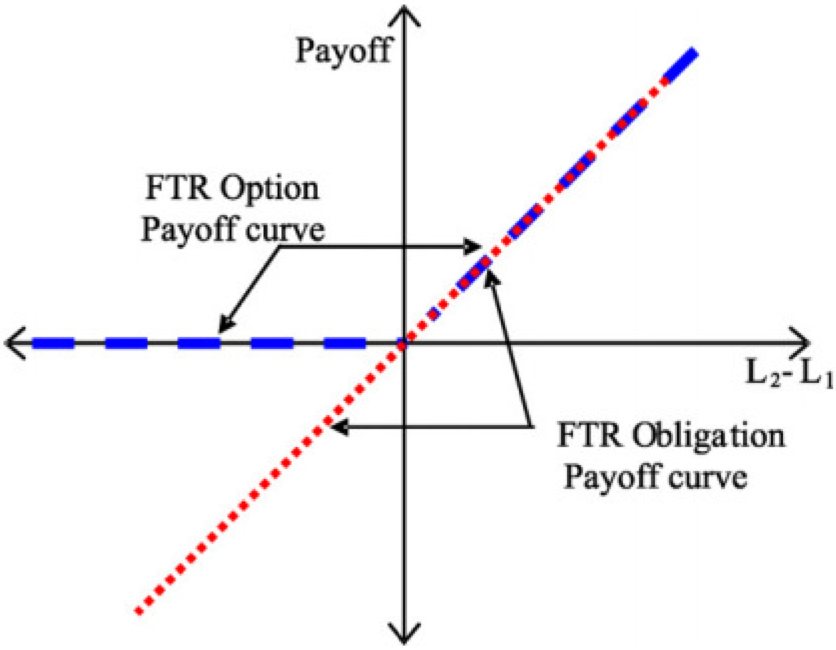
3.3 TRANSMISSION RIGHT OPTIONS AND OBLIGATIONS

3.3.1 General Issues with 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.

participants are not exposed to any liquidity risks or PX fees of their nodal exchanges (which in fact do not exist for all nodes).

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:[24]

> "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."

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

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 $\max(0, P_2 - P_{hub}) + \max(0, P_{hub} - P_1) \neq \max(0, P_2 - P_1)$. 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[25]) leading to better price discovery and efficiency.

Thus FTR obligations facilitate a wider range 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 be shown that under certain conditions FTRs increase market power (Joskow and Tirole,[26] Bushnell[27]) whereas in other circumstances they reduce it (Stoft[28]). In particular, when traders cannot arbitrage price differences across markets by buying FTRs, market power is enhanced. 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

[25] *R. Treinen and A. Papalexopoulos, (2003) ECCO International, "Important Practical Considerations in Designing an FTR Market," IEEE Power Engineering Society Summer Meeting.*
[26] *Joskow, P. and J. Tirole (2000). "Transmission Rights and Market Power on Electric Power Networks," RAND Journal of Economics, 31: 450-487.*
[27] *Bushnell, J. (1999). "Transmission Rights and Market Power," The Electricity Journal, 77-85.*
[28] *Stoft, S. (1999) "Financial Transmission Rights Meet Cournot: How TCCs Curb Market Power," The Energy Journal, 0: 1–23*

hold the FTRs (Young et al[29]). Gilbert, Neuhoff and Newbery[30] showed that in efficiently arbitraged uniform-price auctions, generators will only obtain contracts that mitigate their market power. Contracts inherited or bought in a "pay-as-bid" auction can, in contrast, enhance 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. Similarly, the market demand for options has been quite 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 two 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.

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* (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

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[29] *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.*

[30] *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*

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 Transmission Capacity 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. This will require further investigations, given that it is often argued that the network capacity should be released in a conservative manner to prevent exposure to risks of non-delivery by market participants.

- In cases where a country is interconnected with neighbouring states via numerous links, eg, 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. 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. 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. This and other alternative approaches will be further investigated.

3.4.3 Locational Marginal Pricing

In Locational Marginal Pricing (LMP) markets, there is a different price at each network node, 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 a specific 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, the electricity price is equal for all nodes. In the event of congestion, electricity prices can vary from node to node. These price differentials give rise to a congestion surpluses 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, ie, no transmission constraint will be violated.

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 is 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. 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.

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[31]). 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

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

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.

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 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.

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.

- 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 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.

One important advantage of this market setup is that it supports the coexistence of multiple PXs, allowing for easier transition from the current market setup of national PXs. The most important drawback of Flow-Based Market Coupling is the simplified network model. Efficiency of system operation is widely significantly dependent 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.

Alternative approaches to evaluating ATC will be further investigated.

In this 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.

3.4.6 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 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.

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[32]). The auction maximises payments using an optimisation model, subject to satisfaction of simultaneous feasibility (Ma et al[33]). In some markets, there is also provision to allocate FTRs to merchant transmission providers (ie 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 would seem to be an explicit device to facilitate new investment.

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 has been liquid for counterflow FTRs,[34] thus allowing for more capacity to be sold. This increased liquidity, attracts larger amount of trades and participants and contributes to the market efficiency.

3.4.7 Nord Pool

The Nordic market employs market splitting to co-ordinate cross-border trading and allocate capacity on the interconnectors.[35] Currently, it consists of 9 price zones and is widely regarded as one of the most efficient and successful electricity markets worldwide. 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

[32] *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*

[33] *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*

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

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

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.

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. Unlike FTRs, they are not a claim on the congestion surplus and are not linked to the physical capacity of the system. Consequently, as long as there are parties willing to underwrite these contracts, sufficient volume is allocated.

3.4.8 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. 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 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. TSOs may be resistant to such a proposal.

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, knowing that it will be allowed to recover its costs one way or another by its regulator, will seek to minimise risk. 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. Plainly this is an issue that requires further examination as to the best approach to be adopted.

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[36]

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

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 one to three 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

CfD contracts are not auctioned but traded as futures or OTC (90% of OTC contracts are reported for clearing to the exchange) contracts 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. The majority of CfD contracts are traded through OTC contracts 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)* 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 probably 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 transmission right with longer durations than one year. 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.

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.[37] 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.[38] 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.

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 due to absence of counterparties that have a natural hedge. However if sufficient liquidity is present,

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[37] *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*

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

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.[39]

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

[39] *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*

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,[40] 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:[41]

- 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 Nordpool was about € 70 bn. About 60% of this was due to power exchange trades and 40% due to OTC products.
- 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

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

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

and for OTC brokered contracts. We can see that the volume traded in Nordpool 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 3.4: 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 pricing 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.

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.

Nonetheless, overall, IFA has 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.

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[42] (2010) 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.

[42] *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*

4. EMERGING ISSUES

4.1 EMERGING CONCLUSIONS

Our analysis to date, which needs to be tested in further discussions with stakeholders, leads to a number of conclusions of varying degrees of robustness. We tentatively present six key conclusions at the present stage.

- 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. 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. Thus if the IFA has an NTC of 2 GW, the relevant TSOs could continue to issue FTRs until, for example, French traders, generators or suppliers held 10 GW of FR->GB FTRs[43] provided others held 8 GW of GB->FR FTRs. The potentially substantial volume of virtual trading could considerably increase the size of the contestable market in each country and hence intensify competition in each market. While it would be possible to create PTRs that were firm obligations, and to continue issuing and netting them with the same result, it is likely to be more cumbersome and costly than creating FTRs.

- 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 a second-best way of helping to finance a 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

[43] *A FR->GB FTR entitles the holder to receive the excess of the GB price over the FR price but to be liable for any excess of the FR price over the GB price, and conversely for a GB->FR FTR.*

regulations. Such withholding can be readily prevented under the existing practice of use-it-or-lose/sell-it (UIOLI or UIOSI).

- 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.[44] 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.

- TSOs should be required to issue FTRs 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). 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.

- 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.

4.2 FUTURE WORK

We will complete our round of interviews of stakeholders, and also present stakeholders with emerging conclusions for discussion. We will, if practical, achieve this in part by

[44] *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*

attending the next Florence Forum, and also by holding a workshop with invited guests, scheduled for 31 May 2011 in London.

We have indicated in the text where gaps in information collection and analysis still exist. In particular, some desirability issues still require analysis, and the analysis in Chapter 3 needs to be rounded out to clarify arguments for the best solution. Implementation issues remain to be considered.