TRANSMISSION RISK HEDGING PRODUCTS –

AN ENTSO-E EDUCATIONAL PAPER

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DISCLAIMER:

ENTSO-E has prepared this analysis to serve as a basis for discussion with ACER and stakeholders on long term risk hedging products. The purpose of this paper is purely didactic and is simply intended as a means to inform further discussion on long term risk hedging products. It does not constitute any position from ENTSO-E or any of its members on this topic. ENTSO-E and its members reserve the right to formulate its own views on the issues raised.

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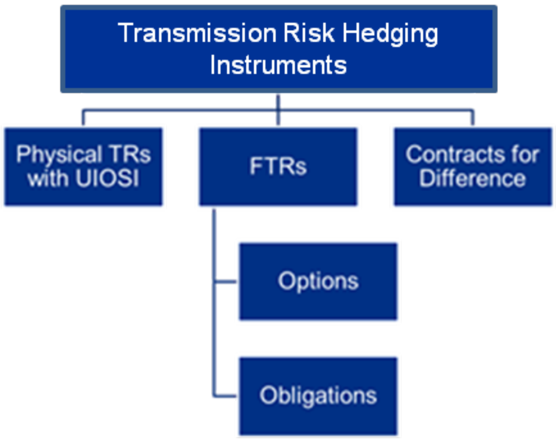
EXECUTIVE SUMMARY

In order to contribute to ongoing discussions regarding forward capacity allocation this educational paper describes different forward hedging products that can be offered to hedge the risk associated with trading between different hubs separated by congestion. This paper focuses on three different kinds of transmission risk hedging products recognized by ENTSO-E and defined as followed:

- **Physical Transmission Rights (PTRs)** are linked to cross border capacity and managed by TSOs providing the option to transport a certain volume of electricity in a certain period of time between two areas in a specific direction. The use-it-or-sell-it mechanism ensures that not nominated capacities get automatically sold in the day-ahead market.
- **Financial Transmission Rights (FTRs)** are linked to cross border capacity and managed by TSOs or subsidiary entities and can be implemented to directly hedge risk in the day-ahead markets. FTRs as options entitle their holders to receive a financial compensation equal to the positive (if any) market price differential between two areas during a specified time period in a specific direction. FTRs as obligations in contrast also oblige holders to pay for a negative market price differential.
- **Contracts for Differences (CfDs)** are contracts between two parties, where the underlying value is the price difference between two reference prices. Should the price difference be positive, then the buyer will receive money from the seller; should the difference be negative, then the buyer has to pay the difference to the seller.[1]



Chapter 1 shows the main characteristics of different forward hedging products and their functionality as risk hedging instruments, considering energy trades, speculative behaviors and counterparty risks. **Chapter 2** describes different trading systems in Europe and USA. The first two parts aim at providing an insight on different transmission risk hedging products as a basis for an evaluation through different criteria. In this context the **Chapter 3** evaluates the products, followed by **Chapter 4** which summarizes the pros and cons resulting from the analysis. Since the paper has an educational purpose and is not aiming at giving a recommendation or a position on the product to be implemented in European forward markets, the identification of pros and cons shall be a basis for further work on this topic.

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[1] Though we refer to CfDs as defined and used in the Nordic market in the Paper, this definition shall help to understand the nature of these products. In the Nordic market the two reference prices are the relevant area price and the system price.

CONTEXT AND MOTIVATIONS

The background for this educational paper is the ongoing European work regarding the framework guidelines (FWGL) on capacity allocation and congestion management (CACM) as basis for Network Codes developed by ENTSO-E. TSOs shall according to the target model for the forward market sell financial transmission rights (FTRs) or physical transmission rights (PTRs + UIOSI) unless appropriate cross-border financial hedging is offered in liquid financial markets on both side of an interconnector. Within the elaboration of CACM Network Code the European Commission decided to not include forward markets at this point, but rather to request start drafting at a later stage (October 2012). ENTSO-E takes this an opportunity to gain a deeper understanding of the topic with this educational paper. Therefore different forward hedging products for cross-border electricity transmission trade will be analyzed and evaluated in the following sections in order to have a clear understanding of their main characteristics.

1. TRANSMISSION RISK HEDGING PRODUCTS

Price spread volatility between energy markets creates the need for derivatives, which allow Market Participants to hedge against the market price differentials which result from transmission congestion. There are different concepts which aim at the efficient utilization of the existing electricity system and its development through competition. Transmission risk hedging products can contribute to create markets that can limit the risk and enable market participants to manage fundamental uncertainties in the market. The goal is therefore not the creation of liquid markets for transmission rights in itself (physical or financial) but to allow Market Participants to hedge their cross-zonal position. One option is to hold a transmission capacity product, which can be a **physical right to transfer energy** between two market hubs or a **financial right to receive** (or in case of obligations to pay) **the price difference** between these two zones.

If there are liquid financial markets in each of the interconnected areas one alternative to separate cross-border forward products is to use local financial markets for hedging. E.g. by holding different forward and physical positions in each of the local markets, the payoff from different PTR/FTR positions and generation/consumption strategies will be replicated.

This paper is focusing on different transmission capacity products. The following simple examples of different products are illustrating the nature of them. For each of these examples the situation of a generator having a long-term contract to supply energy in a neighbouring market is considered.

1.1 PHYSICAL TRANSMISSION RIGHTS WITH USE-IT-OR-SELL-IT CONDITION

A physical transmission right gives the holder the exclusive right to **use a particular interconnection** in one direction to transfer a predefined quantity of energy from one market hub to the other. The right can be used for buying and selling energy either on OTC markets[2], through Power Exchanges or to meet physical positions in the two markets.

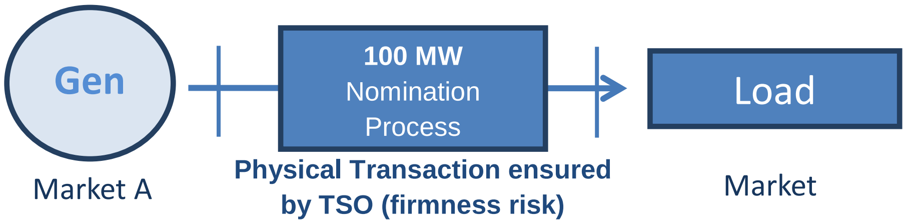
To illustrate the principles of operation we will first look at the market player perspective considering physical contracts between markets with different prices in a market coupled system.

The Generator in market A produces energy in order to meet his contract of supply in market B. In a world of physical contracting it is generally the Generator who will secure interconnector capacity ahead of time (in this case we consider only long-term rights). He will pay a certain price in the primary auction and nominate the energy to be transmitted. This simple example shows that the load in market B is physically served by using the right to transfer 100 MW from market A to B without any participation in the Day-Ahead Markets.

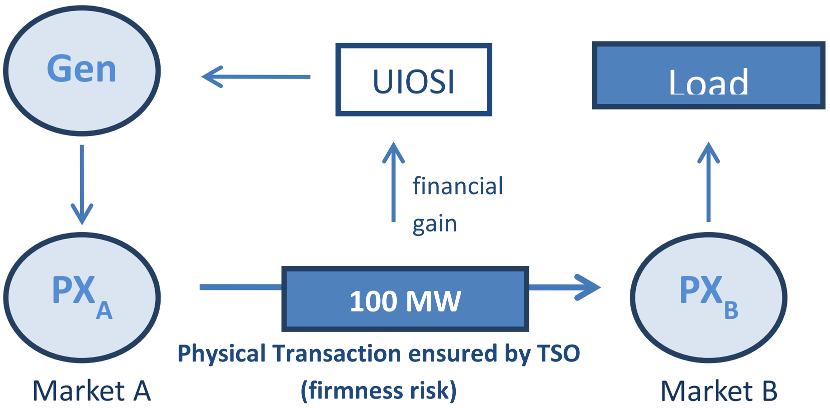
[2] Some Market Participants may prefer trading bilaterally for various reasons (no fees, no collaterals, confidential prices, tailor-made products)

The responsibility for the process of capacity determination and allocation of transmission rights is carried by the TSOs (or by an entity acting on behalf of the TSOs). The issued physical transmission right gives its holder the right to nominate energy transfers between two zones. In this context the TSO (or TSOs' Auction Offices) takes a clear role in the management and allocation of PTRs.

The exercise of PTRs as options is performed through a nomination process. This nomination process must take into account all physical transmission system constraints.



The owner of the PTR can also decide to use it as a FTR according to the UIOSI provision. If the holder does not nominate the right, the right gets resold in the day-ahead market. The owner of the PTR receives the price difference between area A and area B. In this case the Generator will have to participate on the day-ahead level as a seller in market A and as a buyer in market B in order to ensure his energy supply contract in market B.



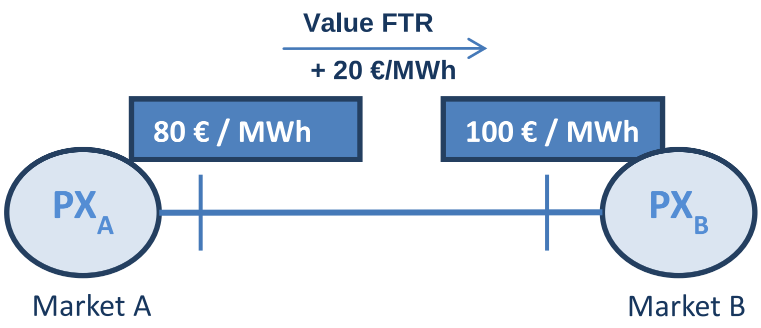
Under the existing regulatory frameworks in the CWE region TSOs have to ensure the availability of PTRs which they issue. Depending on certain preconditions, in case the issued PTRs are higher than the actually available transmission capacity, either the TSOs guarantee the firmness of the PTRs through operational measures such as re-dispatching or countertrading or they curtail the PTRs and compensate the holders. This leads to a risk exposure of TSOs (firmness risk).

1.2 Financial Transmission Right options

In contrast to a physical right, which enables the holder to use a transmission line, the financial right gives the holder the right to **collect revenue** generated by the amount of MW he is holding. The underlying condition for FTRs is the introduction of a functioning day-ahead market coupling. With market coupling TR holders can be assured that their TR is allocated in the day-ahead market in an efficient way, which guarantees holders the revenue to cover costs for selling and buying on the PXs in each market.

Under normal circumstances the revenue is equal to the hourly market price difference, when positive, between market hubs. FTR options are defined in a particular direction, and thus the market price difference represents the price difference between the 'to' market and the 'from' market, which can be positive or zero. FTR is a financial entitlement tradable by itself, and does not result in the right for physical transfer of power between the zones.

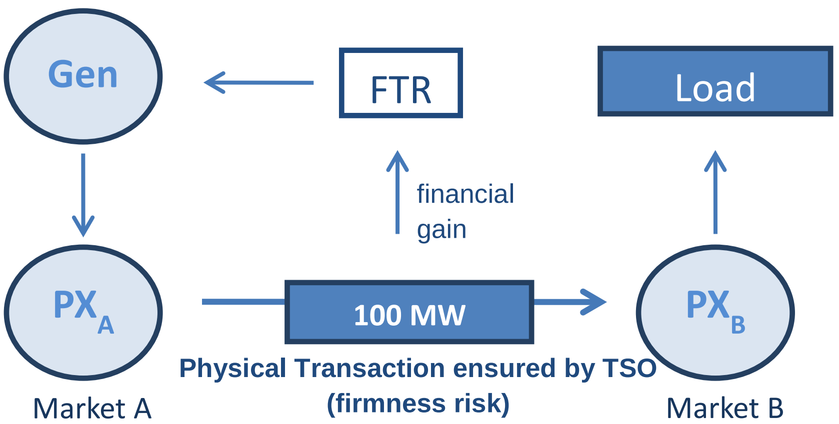
The following example visualizes the effect on FTRs as an option in a market time unit.



As there are no physical rights to flow energy between the markets that can be obtained by individual traders, the Generator has to participate in both markets to ensure the supply of energy. In this example the Generator in market hub A would sell to market A at a price of 80 €/MWh. He serves the load by buying the energy directly in market hub B at a price of 100 €/MWh. The loss of this transaction would amount to 20 €/MWh. This equals the FTR payout of +20 €/MWh.

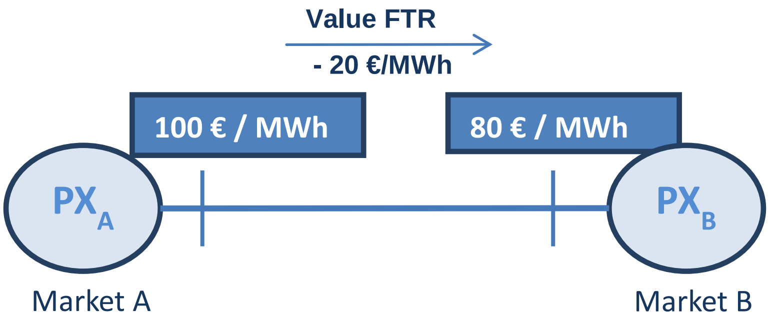
As a conclusion, it can be seen that a seller in the price zone A wishing to establish long-term bilateral contracts with buyers in B needs a long-term FTR in the direction A to B. Assuming the shown prices, the value of the FTR (here +20 €) gives the seller the certainty that, for every market time unit, the price for the bilateral contract he was willing to hedge is covered by the revenue from the FTR. The financial transmission right provides **price certainty** and is thus an efficient hedging towards price spread volatility. The same rationale applies to non nominated PTRs which are resold in the Day-Ahead market coupling.

Since the character of a FTR is purely financial, it is not a physical right and so the physical use remains with the TSOs/PXs. These entities use the physical capacity to buy and sell energy between market hubs under implicit auction arrangements. The yields of these transactions (congestion rents associated to price spread) are used to cover FTRs.
In case the physical capacities are not available, the congestion income from market transactions is insufficient to cover payments to FTR holders. This leads to a risk exposure of TSOs (firmness risk).



1.3 FINANCIAL TRANSMISSION RIGHT OBLIGATIONS

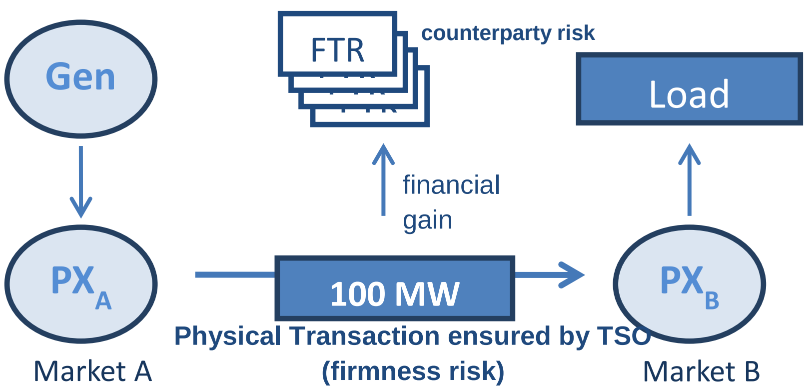
In contrast to a FTR option, the holder of an obligation **is entitled to receive and obliged to pay** the hourly **market price difference** between two areas during a specified time period. The product entails the obligation for owners to pay the respective market price differential if it is negative, i.e. if the price differential is in the opposite direction.



Continuing the last example, if market clearing prices turn out to be vice versa, the Generator in market hub A would sell at a price of 100 €/MWh. He would serve the load in market hub B by buying the energy directly at the local Power Exchange B for 80 €/MWh. The transaction would yield a gain of +20 €/MWh. This gain would be offset by the obligation to pay the negative price difference of -20 €/MWh. In essence, the Generator in market A would obtain a FTR with a negative value. This product, however, would **perfectly hedge** the **bilateral transaction** with the buyer in market B.

With a **FTR option**, the holder could choose not to exercise it. In the above example, he could keep the gain of the transaction (20 €/MWh) and would not have to pay the negative price difference. The **bilateral transaction** would be **hedged and additional opportunities to collect price differences** would occur.

Different from FTRs as options FTR obligations entail the obligation to pay negative price differences. These payments can be used to serve newly issued FTRs for the opposite direction ("netting"). This means that provided FTR obligations are requested by the market in both directions, FTR obligations can be allocated with no direct link to physical capacity, since the opposed transactions would be netted (1 MW export obligation FTR nets with 1 MW import obligation FTR). The allocation process with FTR obligations could (under certain assumptions see chapter 3.1.4) allow TSOs to auction off (in long-term auctions) significantly higher volumes through netting **if FTR obligations are sold in both directions.**



In case the parties having to pay under an FTR obligation default, no payments for FTRs issued in the opposite direction would be available. This leads to a risk exposure of TSOs (counterparty risk) [3] in addition to firmness risk.

1.4 SYSTEM PRICE DERIVATIVES AND CONTRACTS FOR DIFFERENCES

The financial market with Contracts for Difference (CfD) and System price derivatives acts under the assumption of a common market based on the system price. The system price[4] is defined and calculated as the price would have been for the whole region (with all included bidding/price areas) if there were no congestions. In this **sense the whole market area (coupled area) uses the same reference price**, and this reference price is the basis for all hedging of positions.

When congestions occur different bidding/price areas will have different prices, and the price will differ from the system price. Thus**, in order to be perfectly hedged a market player also needs to hedge the difference between system price and the area price** for each of the area(s) that the MP is active (buying or selling) in.

A CfD (as applied in the Nordic market model) is not related to the price difference between bidding/price areas, but between a bidding/price area and the system price. Since both the system price derivatives and the CfDs are related to the system price the volumes of both types of contracts are not directly related to the cross-border capacity. However, the value/price of the CfD is related to the physical capacity between the areas. Further, the CfDs are sold by market players not TSOs. Any interested market player may issue system price derivatives and CfDs. Since TSOs are not exposed to finical risks, CfDs are full financially firm.

A CfD is an obligation. This means that if the area price is lower than the system price the holder of a CfD will have to pay the seller of that CfD (equivalent to FTR obligations in case of a negative price difference).

Other CfDs systems are implemented apart from the system price solution implemented in the Nordic market. For example, as it will be further described in section 2.4, Spain-Portugal border has a CfD market based directly on the market spread associated to the Market Splitting between Portugal and Spain.

1.5 Economics of Transmission Rights for Market Participants

Transmission Rights can be used by Market Participants either to hedge risks associated to cross-zonal positions in the case of Energy transfers (generalizing the examples shown in sections 1.1-1.3) or to maximize benefits in the case of pure Trading business. In order to be able to understand the interest of Transmission Rights for all Market Participants it is important to analyze the economic impact that these products have on agents holding long-term transmission rights.

[3] The counterparty risk is particularly important to consider in case of FTR obligations since the holders of FTRs acquire a financial obligation towards TSOs with no certainty on prices.

[4] This refers to the system price as defined and used in the Nordic market. Other definitions could also be conceivable.

1.5.1 Energy transfers

As explained in Appendix 1.1 "Economics of Transmission Rights for Market Participants", the economic results (Profits & Losses) for a generator with a cross-zonal supply contract and an FTR will be for any price spread:

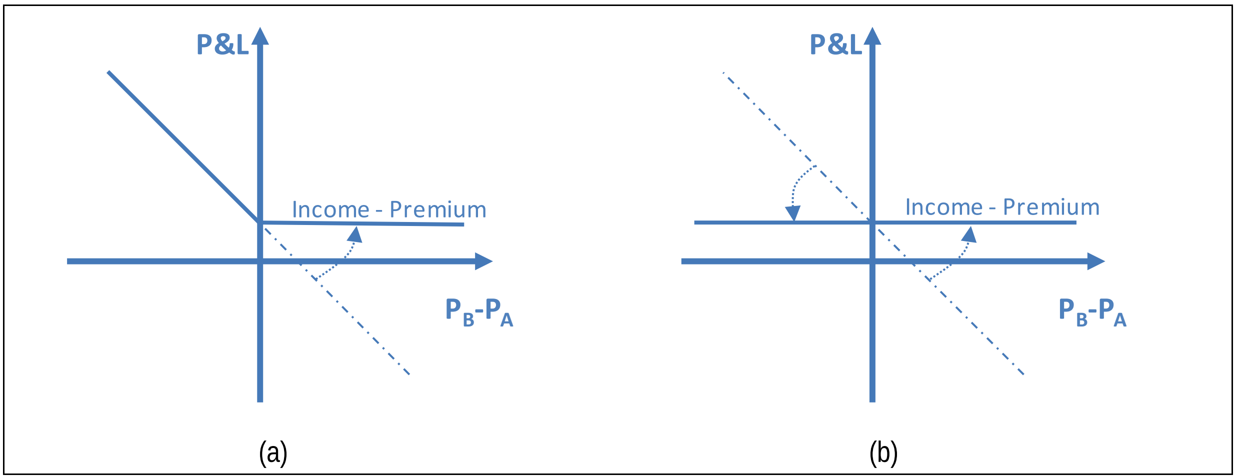


Figure 1: P&L of a generator with a cross-zonal position holding (a) FTR option or (b) FTR obligation

From these figures it can be concluded that **FTRs options** allow hedging the risk associated to the volatility of the price spread by limiting potential losses**. FTRs obligations provide a perfect risk** hedging since the holder becomes insensitive to the price difference between Markets A and B.

1.5.2 Trading business

As described in Appendix 1.1, the economic results (Profits & Losses) for purely speculative purposes with FTRs will be:

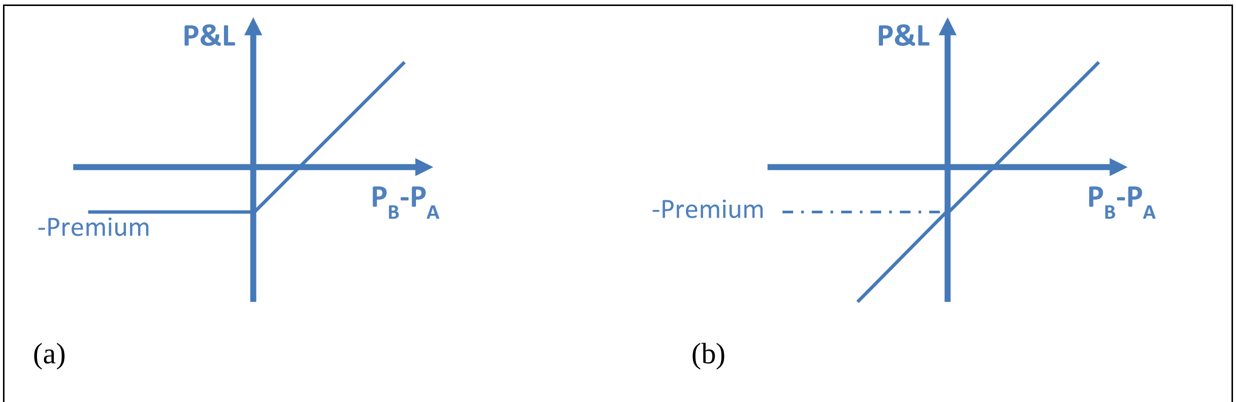


Figure 2: P&L of a trader holding (a) FTR option or (b) FTR obligation

It can be concluded that FTRs allow market participants to benefit from positive market price differences. **FTRs options limit the potential losses allowing benefits at the same time**. On the other hand, **FTR obligations involve higher risk exposure, since the holder could incur in payment obligations.** These products should therefore be available at lower market prices. Traders willing to accept higher risks might therefore prefer FTR obligations.

1.6 Economics of Transmission Rights for the Counterparty

The counterparty is the entity charged of the auctioning and settlement of transmission rights (typically TSOs or auction offices). Considering that the counterparty auctions "n" FTRs (options or obligations) at a marginal price "Premium", the economic results for the counterparty will be[5]:

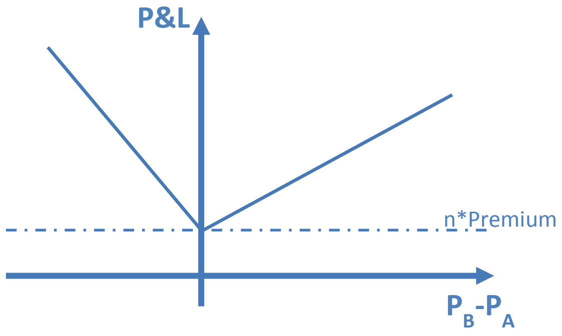


Figure 3: Counterparty's P&L

As justified in Appendix 1.2, there is **no financial risk for the counterparty** associated to the auctioning of **FTRs options or obligations, as long as the capacity available to the day-ahead markets is higher than the capacity allocated in the transmission rights auctions** (the income associated to the capacity allocated through the Market Coupling will remain higher than the costs of FTR).[6]

This however may not always be the case. There might be less capacity available than the underlying capacities of corresponding FTRs that were already allocated by TSOs. This may occur under critical grid situations where TSOs are not able to provide the grid capacities which they have originally made available to the market.

Furthermore, we assumed that the allocating entity has issued FTRs only in one direction. In reality once allocated FTR obligations may be sold again for the opposite trading direction ("netting"). This may lead to situations where more capacity than actually available is allocated to market participants.

2. International Experience

2.1 Physical Transmission Rights (UIOSI) – CWE

Since the Memorandum of Understanding of the Pentalateral Energy Forum on market coupling and security of supply in Central Western Europe, which was signed in June 2007, it is planned to implement a *flow-based market coupling* (FBMC) between the five countries of the CWE (Belgium, France, Germany, Luxembourg and the Netherlands) by mid of 2013.

[5] See Appendix 1.2 "Economics of transmission rights for the Counterparty" for a detailed description.

[6] In any case, all gains and losses which the Counterparty incurs have to be used in accordance with Article 16 (6) of the EU Reg 714/2009. Therefore, the "Profits & Losses" do not represent the financial position of TSOs. They can rather be attributed to grid users. They will take advantage of new investments, higher availability of transfer capacities or lower grid tariffs which are three purposes of using congestion rents specified in Article 16 (6) of the EU guideline mentioned above. These benefits, however, only occur in case of positive financial positions of the Central Counterparty.

As an intermediate facilitation of the FBMC the CWE countries decided in 2008 to start with an *available transfer capacity market coupling* (ATCMC) and to study an FBMC in parallel. In November 2009 TSOs and PXs successfully launched the ATCMC and started to run parallel the FB approach in order to simulate the market impact of it.

2.1.1 PRODUCT DESCRIPTION AND ALLOCATION ENTITY

The available transmission capacity is auctioned in form of physical transmission rights for electrical energy transfer on a yearly, monthly and daily basis. The CWE auction rules set out the terms and conditions for the allocation of available transmission capacity via auctions. In this context CWE TSOs agreed on the joint allocation of the available capacity, which is carried out by the joint auction office CASC (Capacity Allocating Service Company).

To long-term transmission rights (monthly and yearly capacities) which have not been nominated the "use-it-or-sell-it" rule applies. The application of the UIOSI means that traders are free to either use their long-term capacity rights for nomination or to receive the market spread at the day-ahead market. That implies that not nominated capacities are automatically resold on the day-ahead implicit CWE market coupling auctions.

In this context traders who bought long-term capacities do not necessarily need to use their rights physically. Instead of that, any Market Participant could desist from nominating the PTR and use the capacity for financial optimisation and thus earning the value of the PTR (market price difference). Comparing this to financial transmission rights as options, which entitle holders to claim on the price differential between two hubs, the effect of both transmission rights is quite similar.

In CWE, a secondary capacity market has been established. On the one hand, this enables the transfer of allocated long-term capacity to other Market Participants. On the other hand, it enables the resale of capacity acquired at yearly auctions to the Joint Auction Office for the allocation through monthly auctions.

In emergency situations and if no other measures are available, TSOs may have to reduce capacities which were sold to Market Participants to maintain the security of the system and in case of force majeure. For those cases, firmness of capacities is ensured by compensating Market Participants for the capacities that had to be reduced at the market price spread.

2.1.2 AUCTION RESULTS

The following table shows the auction results published by CASC for the monthly auctions held at the border between Germany and France in the first half of 2011:

Monthly Auction Results DE-FR	Offered Capacity (MW)	Requested Capacity (MW)	Allocated Capacity (MW)	Price (€/MW)
January 2011	600	3635	600	6,61
February 2011	625	3860	625	2,78
March 2011	625	5165	624	2,51
April 2011	600	4391	600	0,92
May 2011	300	4320	300	0,54
June 2011	300	4240	300	1,00

2.1.3 MARKET LIQUIDITY

Due to the UIOSI rule not nominated long-term capacities get passed on to the market coupling system for implicit allocation. The Market Participants get compensated with market spread or the marginal auction price in case of explicit auctions run as fallback for the market coupling and thus by the congestion income which was obtained in the d-1 allocation via market coupling. If this condition is not met, liquidity problems can occur, e.g. through a reduction of initial given daily NTC values.

In cases where not all non-nominated capacities can be given to the day-ahead market (ATC<non-nominated capacities) firmness is becoming an issue.

2.2 FINANCIAL TRANSMISSION RIGHTS (OBLIGATIONS) – ITALY

The Italian energy market has adopted a zonal model based on a market splitting mechanism, where producer/sellers are paid the zonal price (P_z) while consumers/buyers pay the National Average Price (PUN[7]).

Through the zonal price mechanism, market participants pay implicitly (the zonal price is higher than PUN for importing zones and lower for exporting zones) a fee for the assignment of rights of use transmission capacity (CCT). CCT is indeed based on the difference between the price of the injection zone (P_z) and the PUN. The CCT is implicitly collected in the day ahead market, whilst for the bilateral contract it is paid by the selling operators directly

In the first months of day-ahead market functioning the high volatility of this fee has triggered the need for market participants to have an instrument (CCC)[8] that allows them to hedge the volatility. The CCC functioning features and the auction model are stated in the AEEG decision n. 205/04.

2.2.1 PRODUCT DESCRIPTION AND ALLOCATING ENTITY

The CCC consists in a 1 MW contract for the price difference between PUN and zonal price allocated by Terna. For each Italian zone annual and monthly CCC are auctioned with the following hourly profile:

- Base load
- Peak load whose underlying is the price difference in the applicable hourly period (7-22) of the working days

CCC permit to substitute an uncertain cost/revenue (CCT) with a certain cost/revenue (the price of the CCC). In fact, the Economical flows arising from CCCs balance CCT's economical flows, when the Energy injected (Ei) is equal to the quantity of CCC.[9]

The CCC allocation is based on multi session auctions. Before each auction, participants are informed for each zone of the maximum quantity of CCC that they can buy. The maximum quantity is defined on the basis of the Terna estimation of the maximum production capacity for each market zone. This value is further reduced for yearly products auction according to the percentage of distribution of the production of each participant in each market zone.

[7] The PUN is equal to the average zonal price in the DAM, weighted by the amount of energy purchased netted of purchases by pumped-storage units and of purchases by neighboring countries' zones.

[8] CCC (acronym) indicates Financial Transmission Rights used to hedge from the risks of Congestion Cost (CCT) volatility.

[9] See Appendix 2 FTR Obligations – Working example CCC

The total amount of contracts to be allocated isn't defined ex-ante by Terna, but it is a result of the auction (algorithm). The objective of the "auction algorithm" is to maximize the difference between costs and revenues that are generated by the allocated CCC, ensuring that the capacity constraints between the Italian zones are satisfied. This means that the potential flows generated by the allocated CCC have to be no higher than equal to the transit limits. The potential flows are "commercially" defined taking into account the injection flows in the reference zone of CCC and the distribution of the withdrawal between the Italian zones (this means that the CCC allocated for zone A creates a virtual flow from zone A to all other zone in proportion of the percentage of withdrawal in all other zones).

2.2.2 AUCTION RESULTS

The table shows the results of the auctions performed in the first nine months of 2011:

	CCC	
MW	Base	Peak
Yearly products	5728	1257
January	2062	961
February	2561	787
March	2431	160
April	2774	1182
June	2006	1449
July	3927	1436
August	2114	1329
September	2856	530

2.3 FINANCIAL TRANSMISSION RIGHTS (OBLIGATIONS) - PJM

2.3.1 PRODUCT DESCRIPTION AND ALLOCATING ENTITY

PJM Interconnection is a Regional Transmission Organization (RTO) which operates the high-voltage electric grid and the wholesale electricity markets that serve 13 states and the District of Colombia. PJM is not owner of the transmission assets which belong to various power transmission companies, most of them belonging to a vertically integrated utility. The design of the market operated by PJM is based on a nodal pricing model.

In this context, Financial Transmission Rights are used by market participants to hedge against the costs between the different nodes of the network. FTRs allocated by PJM are either obligations or options which entitle the holder to a stream of revenues, or charges (in case of obligations), based on the hourly congestion price differences across a transmission path in the day-ahead energy market. Obligations and options are allocated and priced during a same FTR auction (i.e. these two types compete against each other).

FTRs are traded on several market sessions:

- Long term FTR auction: PJM conducts a long term FTR auction for the three consecutive planning periods immediately following the planning period during which the long term FTR auction is conducted.

- Annual FTR auction: each April, PJM conducts an annual auction during which all eligible market participants may bid on FTRs for the next planning period consistent with total transmission system capability, excluding the FTRs approved in prior long term FTR auctions.

- Monthly auctions at which the residual FTR capability (after allocations at the long term and annual auctions) is made available.

- Secondary bilateral markets operated by PJM.

PJM does not own the transmission network assets and is consequently not directly selling the capacity and does not benefit from the congestion revenues. Auction Revenue Rights (ARRs) are the mechanism by which the proceeds from the annual FTR auction are reallocated, mainly to utilities. An ARR is based on the price differences across the specific ARR transmission path that results from the annual FTR auction (i.e. the charge, or revenue, paid to acquire the corresponding FTR). ARRs can either be sold on the annual FTR auction or self-scheduled as FTRs.

ARR and FTR holders do not need to physically deliver energy to receive ARR or FTR credits and neither instrument represents a right to the physical delivery of energy.

2.3.2 AUCTION RESULTS

PJM mainly issues obligations and 85% of them are used for physical hedging purpose (the remaining part is more speculative). A small part of options are also allocated but they seem less relevant for the PJM market design.

A detailed report on the outcomes of the FTR markets can be found in the 2010 State of the Market Report for PJM. As an example see in appendix 3 an extract from this report shows the monthly FTR profits by organization type for the year 2010.

2.3.3 FIRMNESS AND COUNTERPARTY RISK ISSUES

The volume of FTRs (options and obligations) allocated at an auction, results from a *Simultaneously Feasible Test* (SFT) run by PJM. The purpose of the SFT is to preserve the economic value of FTRs holders by ensuring that all FTRs awarded can be honoured.

Under normal system conditions, the actual network capacity permits at least as much transits as the volume of allocated FTR. In this case, PJM collects enough congestion revenues to pay in full the holders of FTRs.

Revenue inadequacy can however occur if the availability of the transmission assets for the day-ahead market is lower than the one modelled in the SFT or if the assumptions on loop flows induced by the adjacent power systems are different. When revenue inadequacy occurs, the shortfall is shared between the holders of FTRs, according to principles agreed by all stakeholders. PJM is not exposed to any financial risk due to revenues inadequacy.

FTRs were paid at 96.9 percent of the target allocation level for the 2009 to 2010 planning period and were paid at 85.2 percent of the target allocation level for the 2010 to 2011 planning period through December 31, 2010.

FTRs obligations induce a higher level of counterparty risk. In order to mitigate this risk, financial guaranty requirements are calculated based on the historical spreads (for 3 years) and, as the case may be, an extra credit requirement in case that the market participant has already experienced a default of payment. Any payment incident or loss is shared between the holders of FTRs. During the year 2007, two important payment incidents occurred for a total amount of $85 million.

2.4 SYSTEM PRICE DERIVATIVES AND CONTRACTS FOR DIFFERENCE - NORDIC MARKET DESIGN

The Nordic model for cross-border trading in the forward time frame is purely financial. It is based on having a liquid system price, equal in the whole Nordic area for any given hour, and a Contract for Difference (CfD) for hedging the local area price against the system price.

2.4.1 FINANCIAL MARKET DESCRIPTION

The Nordic system price is the reference price for most of the contracts in the Nordic financial electricity market. The system price is calculated by Nord Pool Spot in the common day-ahead auction for the Nordic countries. It represents the common Nordic price that would have been achieved in the spot market if there were only one bid area for the whole Nordic area.

Presently there are five bidding areas in Norway, two in Denmark, four in Sweden and one in Finland. Different area prices arise if there is congestion between different bidding areas.

The risk for the MPs in the Nordic market consists of two parts; system price risk and area price risk. To manage the two risk elements and get a perfect hedge a combination of CfD-contracts and forward contracts with the system price as the reference price is needed. Another possibility is that the market player keeps the area price risk and only hedges the system price risk with system price derivatives.

Nord Pool introduced CfD-contracts in 2000. The value of a Nordic CfD-contract is determined by the difference between a certain area price and the system price. The exchange-listed CfD-contracts are Copenhagen (Eastern Denmark), Århus (Western Denmark), Helsinki (Finland), Luleå (Sweden), Sundsvall (Sweden), Stockholm (Sweden), Malmö (Sweden), Oslo (Norway) and Tromsø (Norway). There are CfD-contracts for months, quarters and the three nearest calendar years.

Since the CfD market uses the system price as reference there is no direct relation between the CfDs and the transmission capacities between the market areas. (Although one should notice that buying a CfD-contract in one area and selling on in an adjacent area is the financial equivalent of an FTR obligation). Therefore, the Nordic TSOs have no active role in the CfD market. Instead CfDs are sold by market parties, often ones that own production in the bidding area concerned.

The clearing house (NASDAQ OMX Stockholm AB) acts as the counterparty to both the buyer and the seller once a trade is done on the exchange or once an OTC trade is registered for clearing. The clearinghouse nets (offsets) the portfolio of positions a market player has entered into regarding each contract. The net position of the market player regarding a certain contract is its open position with the clearinghouse.

A CfD is an obligation (not an option). This means e.g. that if the area price is lower than the system price the buyer will have to pay to the seller (via the clearing house) when the contract is settled. In this respect the combination of a financial contract with the system price as reference and a CfD provides a perfect hedge. Contracts related to the system price are sold in various forms.

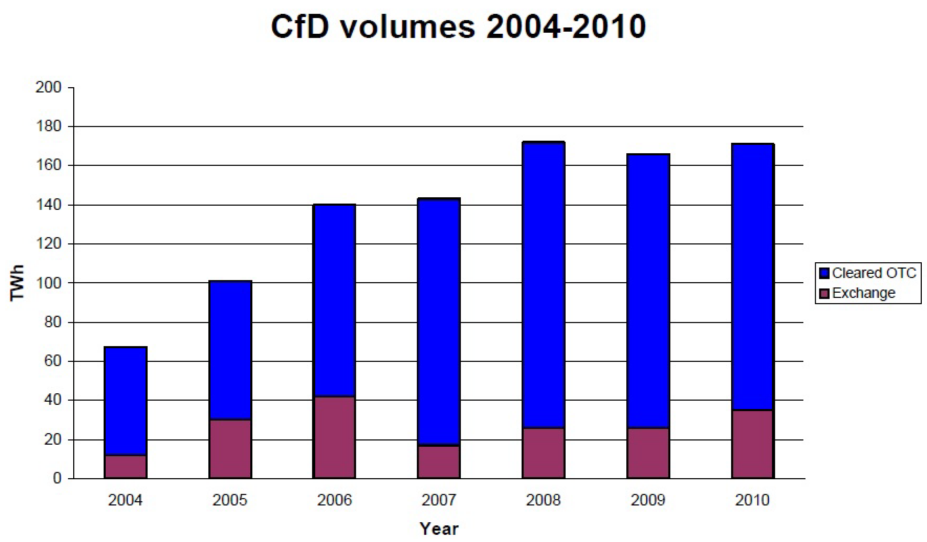
The financial contracts are traded continuously, much like stocks. There are no auctions like the ones for transmission rights. Contracts related to the system price are sold for the following six years. CfDs are sold up to three years ahead.

Since a CfD is a purely financial product with no direct relation to the trading capacities it is always (financially) firm.

2.4.2 MARKET LIQUIDITY

As a general observation it can be said that, whereas system price derivatives are traded and change hands repeatedly, CfD contracts are often just sold once and used for hedging purposes rather than speculative trading. Consequently the liquidity in the system price contracts is very high. This is also one of the main advantages of having a system price as basis for the financial market. For the CfDs the liquidity varies between different market areas, but is generally speaking sufficient.

NordREG published in November 2010 the report "The Nordic financial electricity market (Report 8/2010)". One part of the report describes the development of exchange trade and cleared OTC trade in the Nordic market. There is no transparency regarding uncleared OTC trade but the report cites guesses from interviewed market players that at least 90 % of the OTC trade in exchange-listed contracts is reported for clearing. The following graph, originally published in a report by Elforsk from 2011 ("FTRs in the Nordic electricity market"), shows for CfD-contracts how exchange trade and cleared OTC trade have developed during 2004-2010.



The figure shows the overall CfD volumes and that most of the trade in CfD-contracts is done OTC. The difference between different years reflects partly the general liquidity development in the Nordic market. Trade volumes increased 2004-2008 and reduced from 2008 to 2009 because of the general financial crisis.

It is always possible to trade a CfD since there are market makers in all Nordic contracts (except Oslo CfD-contracts).

2.5 CONTRACT FOR DIFFERENCES – SPANISH - PORTUGUESE BORDER

2.5.1 PRODUCT DESCRIPTION AND ALLOCATING ENTITY

For the moment, the existing financial products are those described in the Spanish regulation (MO 1549/2009) consisting on 1 MW contracts for the price difference between Spain and Portugal for delivery periods of one hour. Since 2009, qualified participants can present bids and offers of these contracts for yearly and monthly timeframes. In this type of non coordinated contracts the buyer (seller) of such a contract has the following rights/obligations:

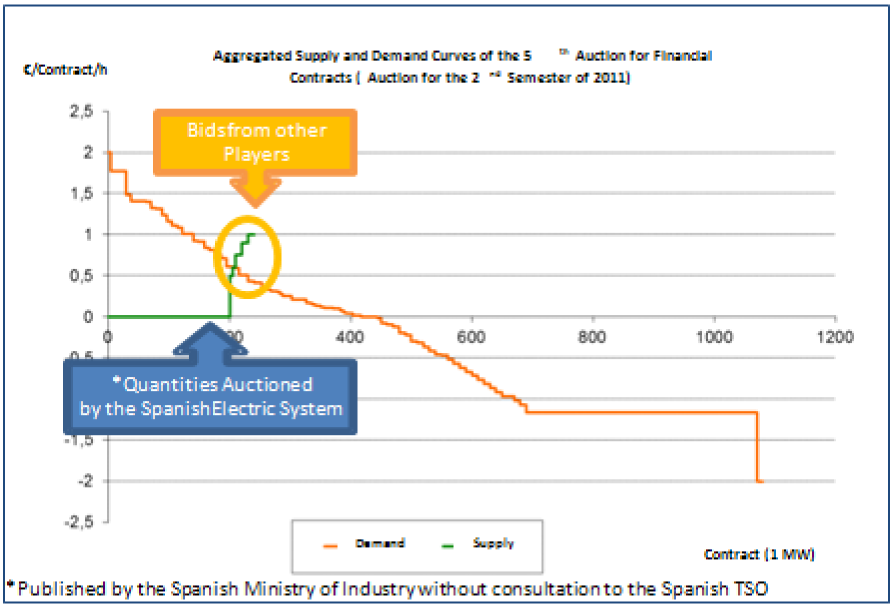
For the hours that the price of the Portuguese zone is higher than the Spanish zone, the Market Participant has the right (obligation) to collect (pay), for each MW acquired on the auction, the Day-Ahead market price differential between the two zones;

For the hours that the price of the Portuguese zone is lower than the Spanish zone, the Market Participant has the obligation (right) to pay (collect), for each MW acquired on the auction, the Day-Ahead market price differential between the two zones;

In order to provide liquidity to the financial mechanism, the Spanish Electrical System also participates in the auction of financial contracts as a selling entity, making a price taker offer. Before each auction, the participants are informed of the amounts of contracts offered by the Spanish Electrical System. The settlement of all the allocated contracts is covered by the Spanish congestion rents (50% of total congestion rents) from the Day-Ahead market splitting in the Portugal-Spain interconnection. As it can be seen, these products auctioned by the Spanish Electric System and settled against the Spanish congestion rents are equivalent to FTRs obligation.

Given this, in reality it is remarkable that in the Portugal-Spain border two different risk hedging products are being auctioned: pure CfDs based on the price difference between Portugal and Spain and FTRs obligation.

An example of an auction where the participation of the Spanish Electric System as a seller entity can be clearly distinguished from the rest of participants' bids is provided below:



OMEL MERCADOS AGENCIA DE VALORES S.A.U. is the entity responsible, under the Securities and Investments Board (CNMV) regulation, for carrying out these auctions. The total amount OMEL receives for each auction is up to 100.000€.

2.5.2 AUCTION RESULTS

The 5 auctions performed up to the moment are the following:

	Period	Quantities Auctioned by the Spanish Electric System [MW]	Quantities Sold by the Spanish Electric System [MW]	Quantities Sold by Other Players [MW]	Price [€/MW/h]
1st Auction	2nd Semester of 2009	100	100	0	2,01
2nd Auction	Year 2010	200	200	0	2,01
	1st Semester of 2010	200	200	0	0,49
3rd Auction	2nd Semester of 2010	200	179	35	0,00
4th Auction	Year 2011	200	200	1	0,34
	1st Semester of 2011	200	200	0	0,10
5th Auction	2nd Semester of 2011	200	200	10	0,60

2.5.3 MARKET LIQUIDITY

In the next table shows a comparison between the financial results for the Spanish system and the results of the 4th Auction during the first four-month period of 2011.

Month	Congestion Income Spanish System. (€)(1)	Income for allocation of contracts.	Payments obligations participants awared. (€) (3)	Payments rights participants awared. (€) (4)	CfD Settlement (€) (5)= (3)+(4)	Payment for carring out the CfD auction. (€) (6)	Total income Spanish system.(€) (7)=(1)+(2)+(5)+(6)	Total income /Congestion Income (7)/(1)
jan-11	194.707	65.472	35.052	-57.460	-22.408	-100.000	137.771	71%
feb-11	77.276	59.136	33.664	-1.120	32.544	-	168.956	219%
mar-11	298.330	65.384	113.848	-298.888	-185.040	-	178.674	60%
apr-11	266.015	63.360	2.384	-404.300	-401.916	-	-72.541	-27%
may-11	22.184	65.472	7.296	-44.240	-36.944	-	50.712	229%
jun-11	98.554	63.360	416	-185.520	-185.104	-	-23.190	-24%
1st Semester Total	**957.066**	**382.184**	**192.660**	**-991.528**	**-798.868**	**-100.000**	**440.382**	**46%**

Indeed, in some situations like NTC curtailments, the Spanish part of the congestion rent from the market splitting (50%) is not sufficient to cover the payment obligations acquired by the Spanish Electrical System in the CfD Auctions (to cover the payments day-ahead NTC should at least double the amount of contracts offered by the Spanish System).

3. Evaluation

The evaluation of different risk hedging products considers both market participants' and TSOs' perspectives. Generally speaking there are different aspects to be considered and therefore markets are distinguished in day-ahead markets for the acquisition of energy and auctions for the acquisition of long-term transmission rights.

3.1 Market Liquidity

3.1.1 Volume of Transmission Rights

One important question regarding market liquidity is whether the available physical capacity depends on the design of different long-term transmission rights. In general **PTRs** and **FTRs**, sold by TSOs, are both based on the underlying physical capacity. The volume of these rights is calculated by the TSOs (or TSOs service provider) and made available to the market. From a TSO point of view the offered amount of transmission rights is related to their firmness risk. In this context, the initial volume of transmission rights that is made available to the market will be same with PTRs and FTRs as long as the underlying firmness conditions are equal.

If Market Participants request transmission rights for both directions the amount of capacity allocated through **FTR obligation** auction is more than the capacity allocated through PTRs or FTR options auction due to netting. Once the capacity is allocated in one direction TSO can provide immediately the corresponding capacity in the opposite direction and therefore the volume of transmission rights might be higher.

3.1.2 Day-ahead market liquidity

With **PTRs** and the UIOSI mechanism Market Participants who do not nominate their rights, receive the day-ahead market spread. Non-nominated capacities get automatically resold in the day-ahead Market Coupling. In case forward markets are based purely on financial instruments (e.g. on a combination of derivatives to hedge against variations in system price and **CfDs**), all cross border trades are performed by the day-ahead Market Coupling. Consequently the day-ahead market liquidity enhances through the fact that all available capacity and not only non-nominated capacity (plus some reserved share of capacity) is put at the disposal of the day-ahead Market Coupling. This would also be the case for **FTRs**, whether options or obligations.

Nevertheless for PTRs, and with the introduction of the UIOSI mechanism and market coupling principles, the behaviour of the Market Participants regarding the nomination procedure has changed. Since the launch of the CWE market coupling, the percentage of long-term nominated capacity has dramatically decreased to only 10 to 15% (for most CWE borders in 2011) and raises the available capacity at the day-ahead market.[10] Consequently the potential efficiency gain in terms of Day Ahead market liquidity through FTRs may be rather low.

In this context the question remains in how far more liquidity leads to more efficient market results. In case of perfect markets one could assume that it does not matter for the efficiency if a high demand faces high supply or if low demand faces low supply. The equilibrium price could be in both scenarios the same. But this holds only under the assumption that markets are well developed and that bids can be selected with a very low scaling. Thus, if there is a market with low liquidity and block bids (bids

[10] See Appendix 4 Percentage of nominated long-term capacity (CWE borders/ Dec 10 – Sept 11)

which can only be chosen, if a minimum amount is taken) or large price steps, this market will be more volatile than a market with higher liquidity. It can be assumed that on imperfect markets a higher liquidity leads to a more efficient allocation.

3.1.3 OTC TRADING

A prerequisite for **FTRs** is that cross-border trades will always be handled through the power exchanges. The most likely mechanism to turn FTRs into a physical exchange is to undertake the energy transaction at the respective PX. In this case additional PX fees are required. For a bilateral exchange with FTRs from A to B the Market Participant must buy FTRs from market A to market B. In order to conclude the cross-border exchange the Market Participant sells or consumes the energy in market A (at PX price A) and generates or buys the same amount in market B (at PX price B). The market spread in the PX (if positive) is then paid to the FTR holder (cf. section 1.2 and 1.3.). In this sense the overall transaction results in zero payouts and physical delivery of energy.

Aside from this transaction both parties can bilaterally agree on terms and conditions for the energy contract. Thereby any bilateral arrangement can be facilitated without explicit cross border transactions.

With **PTRs** actors have the possibility to nominate capacity and thus can trade bilaterally without having the PXs involved for the transaction.[11] However, since the nomination process with PTRs is strictly defined over a specific interconnection, PTR do not bring any additional interest compared to FTR holders. Indeed, with PTRs, the best solution for Market Participants who want to establish OTC trades crossing several borders consists in not nominating the PTRs to several TSOs as the capacity will be automatically resold.

A forward market based on **CfDs** is less complex in the sense that any injection and outtake of energy is hedged against that particular area price, and there is no direct link between the two transactions other than the system price. Any market player can make OTC trades within any bidding area, but there is no physical cross-border OTC trade.

3.1.4 PRICE FORMATION

In order to analyse the issue on price formation, the effects in energy markets and markets for transmission rights have to be considered separately.

<u>Electricity market:</u>

When discussing the different transmission rights, one needs to address the question of whether the possibility to nominate with PTR + UIOSI affects the market outcome. When capacity is nominated from the low price to the high price region, there will be less capacity for the D-1 market coupling. The transmission line will be used efficiently, but the question is, whether the bids which are long-term matched could be more efficiently used if they were allocated in the D-1 market.

If capacity is nominated from the high price to the low price region, the capacity given to the D-1 market by the TSO will be netted with the nominations, thus more capacity in the direction from the low price to the high price region will be available.

[11] except for Italy where the declaration to the PXs is necessary

Another question is if a company in an importing region with market power could influence the market result by nominating the allocated capacity towards this area and then establishing the monopolistic price. This question will be addressed in chapter 3.3.

It might be argued that traders having acquired FTRs or PTRs with UIOSI could tend to be insensible to the market spread, placing bids/offers at any price, which could have an adverse impact on the price formation. However, this effect should be of little significance since the volume of electricity hedged with LTRs compared to the volume of the local electricity market is rather low.

Transmission rights market:

For the analysis two cases are considered:

a) Traders have the same directional price difference expectations

b) Traders have different directional price difference expectations

For TR options in case a) there will be a positive price in the "reasonable" direction. Traders may buy in the opposite direction for a price of zero, if they expect for some hours a flow in the opposite direction. For TR options in case of b) a positive price in both directions is expected.

For TR obligations in case a) there will be a positive price in the reasonable direction. Traders will only buy TRs in the opposite direction if they are getting paid for it. In case b) the advantage of obligations could be compensated, as traders would bid a positive price in both directions. Netting will be possible in this case.

In case a) where traders have the same expectation about the directional price difference and with FTR obligations, market participants would need to get paid to take the capacity in the direction against the expected price difference. In markets with purely financial instruments price formation is based mainly on price expectations and risk strategies. As explained earlier, the CfD price is based on the expected price difference between the system price and the area price. If the CfD has a value above zero it is expected a higher area price than the system price.

3.1.5 Market Liquidity with CfDs

In financial markets based on system price derivatives and CfDs liquidity differs between the two types of products. Regarding system price contracts market liquidity is very high. This is in fact one of the key reasons for having a common system price for several bidding/price areas. The contracts are used for both speculation and hedging, and change hands many times.

CfDs are often just sold once and used purely for hedging. Liquidity of CfDs varies between different market areas, but is generally speaking sufficient. Since there are market makers for all listed contracts a trade can always be made.

3.2 HEDGING AND SPECULATION

Hedging with LTRs

Transmission rights allow contracting parties to hedge risk when making sales across borders or between different price zones.

PTRs with UIOSI entitle their holders to carry out electricity transfers and give them the opportunity to manage price differences in opposite direction to their transaction by not nominating the PTR. In this context, PTRs with UIOSI form an effective price hedging instrument as the underlying electricity transfer possibilities give price certainty to the Market Participant holding a cross-zonal bilateral contract as well as the UIOSI mechanism allows the realisation of arbitrage covering price differences between market areas when not nominating the PTR. In terms of risk hedging, **FTR options** are completely equivalent to non-nominated PTRs with UIOSI.

FTRs obligations entitle their holders to get paid the positive price difference as well as to pay the negative price difference to the auctioning entity. In this context, FTRs obligations make Market Participant insensitive to the price difference between two zones by limiting both, profits and losses. Therefore a FTR obligation provides the market player a complete hedge. On the other hand, these products prevent holders from getting potential benefits from positive price differences, but in a well functioning market that will be reflected in a lower auction price compared to FTR options and PTRs. Obligations will therefore provide a cheaper hedge. Thus, as it can also be seen in the Figure 1 in section 1.5.1, that **FTRs options** allow hedging the risk associated to the price spread without preventing holders from taking advantage from profitable price differences while FTRs obligations make holders completely insensitive to any price difference, if the market participant has a physical position in both markets.

The combination of system price derivatives and **CfDs** provide the trader with a perfect hedge in a given area. If a market player is active in more than one area, e.g. generates in one and sells/consumes in another, he may hedge his positions in both. In this case selling a CfD in one area (where he generates) and buying one in the other (where he sells/consumes) is the financial equivalent of a FTR obligation.

Speculation with LTRs

Transmission rights may also be of interest for contracting parties that do not participate in the day-ahead market and trade transmission rights purely for speculative purposes. The participation of speculators can play an important role in the long-term market since their participation may contribute to the liquidity of the market and to reliable transmission rights pricing.

Speculators forecasting price differences will be interested in buying **PTRs with UIOSI** (which they will not nominate) or **FTRs options** since both products provide the same potential benefits with limited losses. Thus, as described in section 1.5.2, it can be concluded that speculators will be mostly interested in FTRs options (or non nominated PTRs with UIOSI) rather than obligations since FTRs options limit their potential losses (no negative payouts) allowing the same benefit.

In case of **FTRs obligations**, trading these products for speculative purposes could be less attractive since holders bear the risk of having to pay negative price differences. On the other hand, regarding higher financial risks, these products should be available at lower market prices. Traders willing to accept higher risks might therefore prefer FTR obligations.

CfDs can give a perfect hedge for market participants between two market areas or with a system price. Similar to the case with FTR obligations, speculating in CfDs involves higher financial risks (no physical positions) compared to PTRs and FTR options. System price derivatives are liquid and stable and often used for speculation.

3.3 Market Power

Market power needs to be discussed under two different aspects:

- Market power in wholesale day-ahead markets and
- Market power in transmission right auctions

Regarding wholesale day-ahead markets especially the case with a producer´s monopoly in an importing region should be considered: If there is one market with limited interconnector capacity to neighbouring markets and monopolistic producer/s with market power, this producer may buy PTRs and thus increase his market power. Also with FTRs his market power could enhance, since the monopolistic producer/s could buy the FTR and would thus maximize his profits on the full demand curve. The question is, whether the monopolist has the highest willingness to pay for the transmission right or not. If this is not the case and competitors receive the rights, transmission rights will mitigate market power. However, it can be argued that the monopolist has the highest willingness to pay (see Appendix 5).

Regarding transmission right auctions, it is possible that only a small group of participants is bidding for transmission rights. Market participants wishing to buy TRs could organize themselves in order to reach lower prices. This risk can be lowered through decreasing barriers for market entry and monitoring of auction results.

In order to be able to nominate capacity **PTR** holders are usually requested to sign Nomination Contracts and/or Balancing Responsible Contracts (depending on the country) and to install appropriate IT-systems. **FTRs** by contrast have a purely financial character, without any nomination process and thus lower contractual and technical effort. Less complexity could therefore lower the market entry barriers so that more traders request market access. This will consequently increase competition.

The value of **CfD** is based on the expected price differences between bidding zones. To change these expectations you will need to have a relatively dominant position in the physical market.

3.4 Firmness of Transmission Rights

As the forecasted NTC is based on hypothesises, there is always a risk for TSOs when providing the long-term rights to the market. They face financial risks if they oversell rights or if the interconnector fails and are required to compensate transmission rights holders. This risk is related to the firmness and compensation schemes applied.

As firmness rules are not defined for FTRs but there is still the link to the underlying capacity, there is a need to develop provisions which take the interests of Market Participants and TSO equally into account. The TSOs are responsible for the calculation of the forecasted NTC value. One part of it gets allocated as long-term transmission rights. In cases where the calculated long-term ATC and thus the amount of the allocated FTRs turns out to be larger than the actually available daily ATC (due to erroneous assumptions on the networks and flows situations) the TSOs have put themselves at a financial risk depending on the applying compensation scheme and on the guarantees to recover the costs provided by the regulators. There is a need to define rules for this kind of situation, in analogy to firmness rules defined for PTRs.

3.4.1 PTRs with UIOSI

Applying firmness rules within the EU differ from one border to another and due to different timeframes.[12] In order to be in line with the provisions regarding firmness in the FWGL CACM, CWE and SWE member states trading PTRs propose a compensation scheme based on the price differences between the concerned zones with some derogation possibilities with caps on compensation. **Before nomination** (D-1) respectively before a "programming authorisation" deadline (D-2) the acquired long-term rights may be reduced by TSOs due to network security reasons or Force Majeure.

After nomination there is a differentiation between physical and financial firmness. **Physical firmness** is related to the possible technical measures to be taken in order to guarantee a secure network operation and a functioning of electricity market. In this case TSOs have to use re-dispatching or countertrading actions to guarantee the nominated cross-border exchanges. **Financial firmness** regulates the compensation scheme and minimises the risk regarding cross-border trade in exceptional cases when physical firmness cannot be guaranteed.

3.4.2 FTR options and obligations

Regarding the determination of firmness rules there is broad range of possible formats conceivable depending on the timeframe considered; e.g. the possibility to reduce capacity until a certain firmness deadline, e.g. D-1, and full market spread compensation after the firmness deadline. As there is no more nomination stage, a reduction of the FTRs could "only" be applicable in D-1 when calculating the available capacity for market coupling. Within the definition of firmness rules different conditions have to be considered:

- Coverage of the costs of compensations for reductions or of remedial actions to ensure firmness by congestion rents and eventually by tariffs (if CR are not sufficient).
- Implementation of caps (e.g. on the market spread/ on the maximum amount refundable)

As **FTR options** either have a positive or zero payoff, with **FTR obligations** an additional financial risk evolves through the obligation to their holders to pay the potentially negative value of the obligation (counterparty risk), see chapter 3.5.

The approach applied in the US (in all but two markets) is an example of FTR firmness rules where all market parties have to bear losses in case of revenue shortfalls (keeping the risk in the market). In the so called "haircut-approach", FTR holders are only entitled to a pro-rata share of the congestion income, in case of a revenue shortfall and consequently market parties share firmness risks.

3.4.3 Contracts for Differences

In the financial market (including system price derivatives and CfDs) all contracts are fully financially firm due to the fact that there is no direct link to the transmission capacities. Since the pay-outs are guaranteed by derivative exchange and TSOs do not have a role in derivative markets, TSOs are not exposed to any financial risk.

[12] See ENTSO-E position paper "Firmness of cross-border transmission capacity and financial compensation" (July 2011) Appendix II

3.5 COUNTERPARTY RISK EXPOSURE DUE TO DEFAULTS OF PAYMENTS

PTRs and FTR options expose counterparties to similar risks, as Market Participants may be in default of payments for the acquired transmission rights. This risk can be hedged either by a cash deposits or bank guarantees.

FTR obligations introduce a higher counterparty risks for TSOs and Market Participants due to the fact that the FTR holder is obliged to pay if the market spread is negative. Consequently, at the time of acquisition, differently from other TRs, the amount of their financial obligation towards TSOs is not known. Counterparty risks get multiplied if FTRs are passed on between several market participants due to netting. This results in a chain of liabilities between those market participants with a default risk of one or more of these counterparties. The introduction of FTR obligations would therefore require the implementation of a reliable guarantee system. Alternatively, the counterparty risk could be managed by other institutions (for example clearing houses).

The choice between implementing an in-house guarantee system or delegating this task to a third party depends on the regulatory framework (in fact, the introduction of a clearing house would have to be in line with the underlying regulatory framework) and on the related costs. If the risk management solution is linked to high costs it creates an additional market barrier at the expense of market liquidity. In both cases, the guarantee system could be equipped with a default fund for socializing losses as well as a margin system. In the PJM markets for example, despite guarantee deposits, losses resulted from defaults of payments, which were socialised through higher auction fees.

3.6 SECONDARY MARKET

Well functioning secondary markets for long-term rights is an important condition for full allocation and accurate valuation of cross-border transmission capacity rights. As the perfect prediction of demand and supply is not possible accurately ahead of time, secondary markets are an opportunity for Market Participants to adjust their positions by trading long-term transmission rights. Secondary trading should be regarded equally, whether the product is a **PTR** (UIOSI) or an **FTR option,** as there are no relevant differences in resale and transfer procedures between these long-term rights.

In case of **FTR obligations** and without the introduction of clearing houses, the resale of TRs and the transfer of the responsibility to fulfil the obligation to a new Market Participant would need the agreement and the approval of the TSO. If there is clearing house responsible for the credit risk management and market participants are registered and complying with the clearing house requirements, new market participants could acquire a FTR obligation in the secondary market without the approval of TSOs. The potential of **FTR obligations** to be allocated in the opposite price direction immediately after their allocation could subsequently to primary effects lead to more liquid secondary markets compared to FTR options. It could be also argued that with FTR obligations a FTR from zone A to zone B plus a FTR from zone B to zone C can be combined into a FTR from A to C (and the obligation A to C could be split up accordingly), which is not the case for FTR options. Generally it has to be checked against reality, if market participants are willing to buy transmission rights in the opposite direction and if this liquidity effect through netting is given.

In the financial market system price contracts and **CfDs** are sold and re-sold continuously. In that sense there is no primary and secondary market.

3.7 REGULATORY IMPLICATIONS (ENERGY VS. FINANCIAL REGULATION)

A necessary step within the evaluation of long-term rights for cross-border transactions in the EU is to examine if the EU Markets in Financial Instruments Directive (MiFID) applies to hedging products for long-term transmission. In this context the impacts on TSOs and Joint Auctions Offices through an eventual application of MiFID have to be analysed.

In this context ENTSO-E analysed the directive 2004/39/EC on markets in financial instruments (MiFID) and regulation 1287/2006 implementing Directive 2004/39/EC (hereinafter the “Regulation”) as regard record-keeping obligations for investment firms, transaction reporting, market transparency, admission of financial instruments to trading and defined terms for the purposes of that Directive.

One of the main conclusions of this analysis showed that **PTR + UIOSI** shall not be considered as financial instruments since they do not fulfil any of the conditions for financial instruments listed in the Directive. Annex 1 c (9) of MiFID lists different Products, which are regarded as financial instruments and encloses also **CfDs**. Nevertheless, the legal analysis for the Nordic design of CfDs could not be concluded, since there was no clear definition of CfDs.

Regarding **FTR options** the analysis concluded, that they could fall under the category of financial instruments according to the Directive but that TSOs could benefit from exemptions foreseen in MiFID or in the Regulation. Indeed there is a general exemption which could possibly apply to all different long-term transmission products. The Article 2 (c) of the Directive states that entities which correspond to the following definition are exempted from complying with the provisions of the Directive:

“Persons providing an investment service where that service is provided in an incidental manner in the course of a professional activity and that activity is regulated by legal or regulatory provisions (...)”

The fact that generally the revenue generated through auctions could represent a relatively small share of TSOs turnover and is due to be continuously reduced (assuming congestion disappears), it could be used as an argument in favour of the incidental nature of PTR + UIOSI and/or the FTR options. Moreover, one could argue that the issuance and the distribution of FTRs is not part of the core business of TSOs, since this is not part of the TSO tasks in article 12 of Directive 2009/72/EC.

The internal ENTSO-E analysis is subject to the following:

- First, it is important to underline the fact that ENTSO-E does not have major expertise in financial law and therefore their analysis might need to be confirmed on certain aspects (e.g. are FTR to be considered as CfDs as defined in MiFID? Or should FTR be considered as “a derivative contract on the transportation costs for a commodity” (Recital 25 of the Regulation)).

- Secondly, considering that MiFID is currently under review.

MiFID has gone through a consultation process in 2011 and according to the first available drafts, a general exemption may be granted to all products issued by TSOs: “This Directive shall not apply to transmission system operators as defined in Article 2(4) of Directive 2009/72/EC or Article 2(4) of Directive 2009/73/EC when carrying out their tasks under those Directives or Regulation (EC) 714/2009 or Regulation (EC) 715/2009 or network codes or guidelines adopted pursuant those Regulations” (Article 2(n)). Although this clause is very encouraging for TSOs, it does not solve the issue of a potential Joint Auction Office issuing FTRs. ENTSO-E has lately prepared a response to the MiFID consultation proposing a modification of Article 2.1 (n) of MiFID. ENTSO-E proposes a more general formulation including also “any platform performing the allocation of long term transmission rights on behalf the transmission system operator” to be exempted from the application of MiFID.

3.8 IMPLICATIONS ON THE OPERATION PROCESS

Comparing PTRs and FTRs the operational procedures are quite similar (as shown in picture 1), however with PTRs there is a need for enabling a nomination stage before gate closure. This implies the implementation/maintenance of IT systems on TSOs and Market Participants sides, if they wish to nominate. As **PTRs** are widely implemented on most European interconnections the implementation of those IT infrastructures would occur only to some borders. However with **FTRs** all offered capacity is put at the disposal of the daily allocation making it a simpler instrument. The same applies for **CfDs**, where no nomination stage is needed as they are completely independent from any physical transmission capacity.

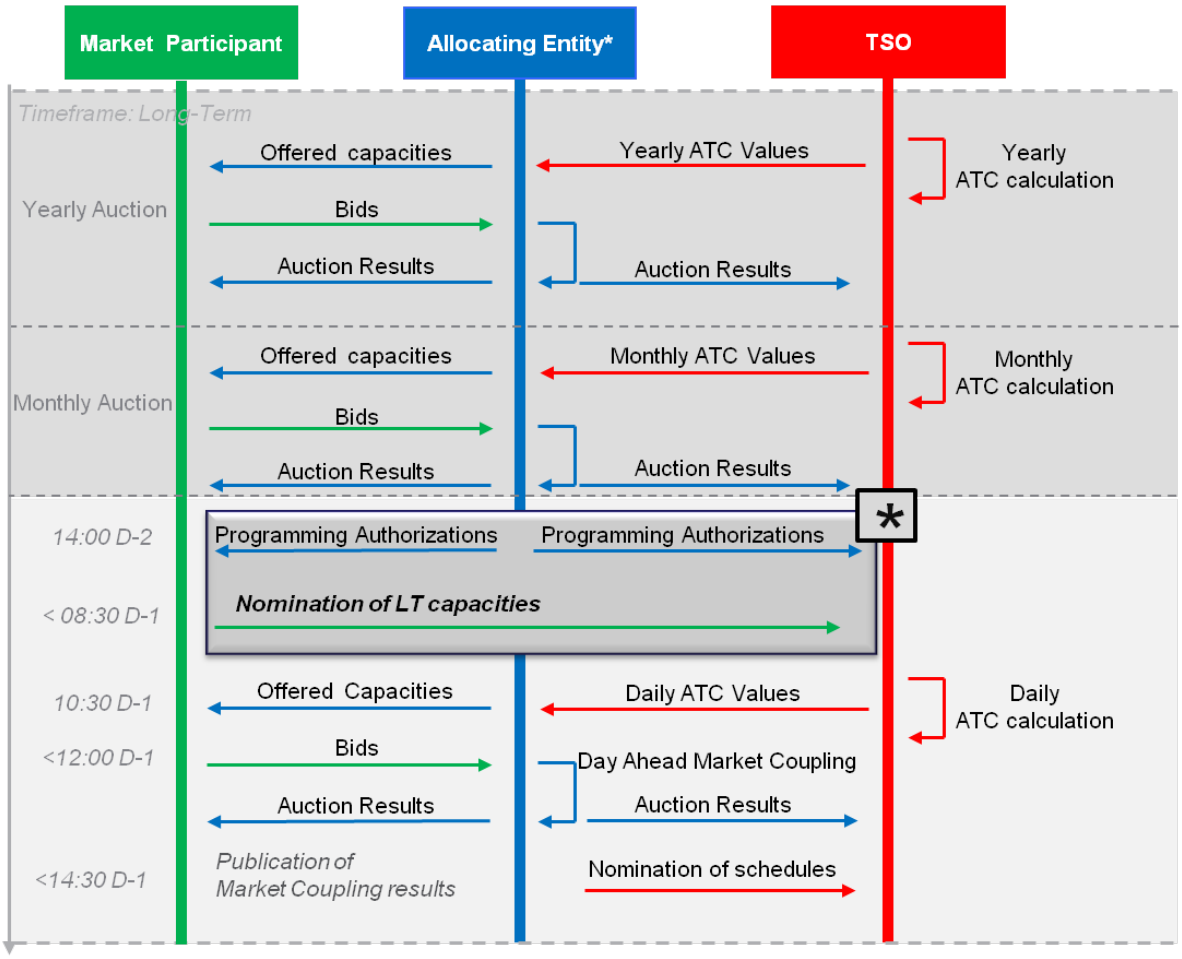
On the one hand the omission of the nomination process may be a benefit for while and on the other hand some TSOs may also benefit from nominations in the capacity calculation.

PTRs and FTRs (option/obligation) can be offered by TSOs and procured by Market Participants. For allocation and settlement procedures both parties are required to establish contracts or a kind of formal agreement. Trading with PTRs implies additionally to those allocation contracts also nomination contracts.

For PTRs the allocations process is managed through Single Auction Offices, which are owned by TSOs (e.g. CASC and CAO). With FTRs the responsible entity for the allocation is strictly linked to the applicable regulation. In this context various entities may be involved in the allocation process of FTRs. Clearing Houses for example could act as a neutral counterpart for all Market Participants. For FTR obligations, as there is a significant counterparty risk, there is a need for Clearing Houses to mitigate financial risks.

CfDs contracts are allocated by any interested market party. Market Participants willing to use CfDs for transmission risk hedging will be able to do so without entering into any kind of contractual relationship with the TSOs.

However clearing houses are required for the overall financial settling. Additional costs resulting from the reorganisation of operative processes due to the implementation of clearing houses have to be taken into account.



Picture 1: Process steps of LT-auctions PTRs/FTRs **(* without nomination stage in case of FTRs)**

4. CONCLUSIONS

In this paper different risk hedging products that can be offered to the market for cross border trade are described. A set of evaluation criteria are used to analyze the nature and crucial characteristics of transmission rights and their impact on cross border trade. In this context a list of pros and cons was elaborated to summarize the overall findings from the analysis.

Evaluation Criteria		**PTR with UIOSI**	**FTR options**	**FTR obligations**	**Financial market** *(CfDs and System price derivatives)*
Volume of Transmission Rights	**Pro**	-	-	Netting immediately after allocation possible	-
	Con	No netting immediately after allocation	No netting immediately after allocation	-	-
Day-Ahead Market Liquidity	**Pro**	-	100% NTC available for DA Market Incentive to participate in DA market for cross-border trade	100% NTC available for DA Market Incentive to participate in DA market for cross-border trade	100% NTC available for DA Market Incentive to participate in DA market for cross-border trade
	Con	Less than 100% NTC as the directly nominated ("used") part is not given to the MC	-	-	-
OTC Trading	**Pro**	No need for participation in DA market – Less complex	-	-	-
	Con	-	No direct cross-border OTC (equivalent trade more complex)	No direct cross-border OTC (equivalent trade more complex)	-
Speculation	**Pro**	Less financial risk for speculators (only positive payouts)	Less financial risk for speculators (only positive payouts)	Lower auction price (higher return for speculators)	Lower auction price (higher return for speculators)
	Con	-	Higher auction price (less return for speculators)	Higher financial risk for speculators (negative payouts)	Higher financial risk for speculators (negative payouts)
Hedging	**Pro**	Effective Hedge (price differences covered)	Effective Hedge (equivalent to PTRs)	Complete Hedge (price differences in both directions covered)	Complete Hedge (price differences in both directions covered)
	Con	**-**	**-**	**-**	**-**
Counterparty Risk Exposure to defaults of payments	**Pro**	No negative payouts	No negative payouts	-	-
	Con	-	-	Negative Payouts involving several market participants– CH necessary	Negative Payouts involving several market participants – CH necessary
Implications on the operation process	**Pro**	Possibility to nominate (Flexibility to use the capacity physically)	No Nomination Stage	No Nomination Stage	No Nomination Stage
	Con	Nomination Stage (operational process needs to be handled)		Clearing House necessary	Clearing House necessary

Looking at the core arguments regarding **PTRs with UIOSI** it becomes clear, that one main advantage is that Market Participants have the possibility to choose between the physical and the financial use of the transmission right with the UIOSI mechanism. A proof of their good operability is that they are widely implemented on most European interconnections and consequently would not cause much effort for implementation. However it should be taken into account that the capacity which is nominated explicitly is not made available to the day-ahead market and thereby decreasing its liquidity. Though, referring to the nomination process of PTRs, an increasing number of traders refrain from their right to nominate. Consequently the negative impact on day-ahead market liquidity is rather limited.

Since **FTR options** are relatively similar to PTRs with the UIOSI mechanism there are several parallels which lead to similar advantages and disadvantages. However FTR options facilitate trading processes through more moderate market requirements. As there is no nomination stage with FTRs the complexity of the general operational process can be reduced (resources, IT-Systems, contractual arrangements).Though in cases where the hedge is set up through PXs the underlying financial transactions (trading on PXs, procurement of FTRs, …) leads to a higher degree of complexity with FTRs, which on the other hand incentivizes increased liquidity on the day-ahead market.

One of the main benefits of **FTR obligations** is their potential to provide a complete hedge to market participants as long as they have a physical position in both markets[13]. Furthermore, as FTR obligations can be allocated in the opposite price direction immediately after their allocation (netting) the volume of transmission rights might be higher. However additional arguments arise from the financial obligation to pay negative price differences between two zones. Though this creates a higher financial risk, there is a positive effect on revenues, due to lower auction prices. Consequently it depends on each trader's individual risk strategy which product is most suitable for speculation. The analysis showed that there is a counterparty risk exposure with FTR obligations[14] due to possible defaults of payments. In order to mitigate these risks, reliable guarantee systems or financial institutions (e.g. clearing houses) need to be put in place.

Similar to FTR obligations the analysis showed that a **CfD** (together with a system price derivative) provides a complete hedge for a market participant aiming to hedge his positions. Additionally, two CfDs (one sell and one buy) will give a complete hedge for market participants between two market areas as long as they have a physical position in both markets. Different from PTRs, CfDs are not issued by TSO. Instead they can be issued by any interested market player and therefore financial institutions or market operators acting as a clearing house providing market players with trading systems are required.

Additional to economic issues the paper deals also with regulatory aspects and mainly the question whether a **financial regulation** (MiFID) could be applicable

Regarding the definition of **firmness rules** for long-term transmission rights there is a need to balance the interests and risks of all market parties. It is important to consider that a high level of firmness and without proper cost recovery rules, TSOs are compelled to offer less capacity in order to limit their risks due to shortfalls. Simultaneously with a high level of firmness Market Participants are willing to pay more for the transmission rights. With a low level of firmness the opposite happens. Generally speaking all parties involved should bear a certain risk. Regarding the definition of firmness rules applying to PTRs and FTRs the right balance has to be found. In case of CfDs, TSOs do not have a

[13] Note that for small market parties, their physical positions might be significantly affected in case of an unplanned outage of a generation asset.

[14] Assuming that obligations are sold in both directions.

role in derivative markets and consequently are not exposed to any financial risk (full financial firmness).

Finally there are still open issues which might need further investigation, such as: Does more liquidity lead to more efficient market results? Does market power influence price formation? Under a FTR obligation regime - Is netting possible though market participants have same price expectations? How could netting be enabled? As already mentioned, this paper does not intend to give a recommendation or a position on the product to be implemented in European forward markets. The result of the analysis are several pros and cons for every individual product, which shall form a basis to elaborate as next step a position paper on this topic.

APPENDIX 1 ECONOMICS OF TRANSMISSION RIGHTS

1 <u>Economics of transmission rights</u>

Transmission Rights can be used by Market Participants either to hedge risks associated to cross-zonal positions in the case of <u>Energy transfers</u> or to maximize benefits in the case of pure <u>Trading business</u>. In order to be able to understand the interest of Transmission Rights for all Market Participants it is important to analyze the economic impact that these products have on the agents that hold them.

It is initially considered that the market participant has a Financial Transmission Right option (or a non nominated Physical Transmission Right with UIOSI condition which is equivalent in terms of economic results) and then the particularities of Financial Transmission Rights obligations are commented. For the sake of simplicity the assumption that market participants buy the same quantity of transmission right as the energy they will buy/sell in the day-ahead market has been considered.

1.1 Energy transfers

This case is the generalization of the example in sections 1.1 to 1.3 above, of a generator in market A having a long-term contract of supply in a market B. The case is again explained but for any possible resulting price spread.

Presenting the Profit & Loss (P&L) account of this generator, there will be a "fix" income related to the difference between the contract he signed for supplying in market B and its production costs, and a variable cost associated to its participation in markets A and B as seller and buyer (P_B - P_A).

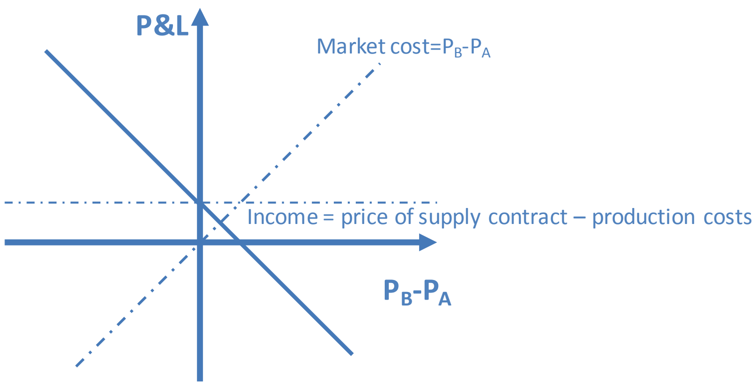


Figure 1: P&L for a generator with a cross-zonal position

From this figure it follows that the generator is exposed to possible losses if final price spread becomes higher than the price of the supply contract. An **<u>FTR option</u>** from Market A to Market B allows him to hedge this risk by getting paid (P_B - P_A) when positive at a cost (Premium) that will be the marginal price resulting from the FTR auction.

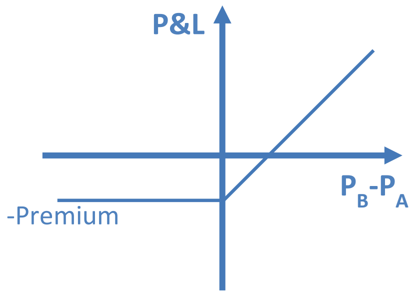
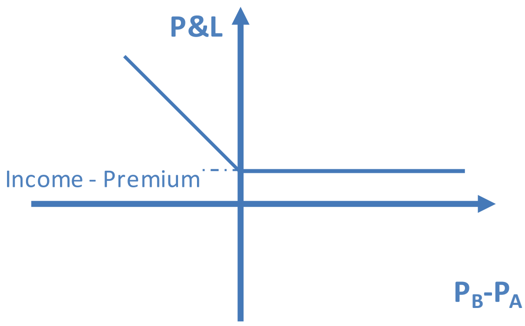


Figure 2: P&L associated to an FTR option

Then, by the addition of Figure 1 and Figure 2 we can represent the total P&L of the generator holding an FTR option from market A to market B.



$$\textbf{\textit{P\&L=Income}} - (P_B - P_A) \textbf{\textit{ - Premium}} \quad ; \quad if \quad P_B - P_A \leq 0$$
$$\textbf{\textit{P\&L = Income – Premium}} \quad ; \quad if \quad P_B - P_A > 0$$

Figure 3: Final P&L for a generator with a cross-zonal position + an FTR option

Comparing Figure 1 and Figure 3, it can be seen that, **with an FTR option, the generator in A limits its losses by hedging the risk associated to the volatility of price spread**. In addition, it can be noticed that, in order to avoid losses, the generator should not pay a Premium higher than the Income (price of supply contract).

In the case of an **FTR obligation** from Market A to Market B, the generator will also be obliged to pay the price spread (P_A - P_B) when positive. Given this, instead of Figure 2, the P&L associated to an FTR obligation is now represented by:

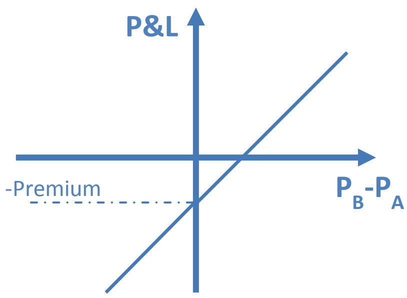
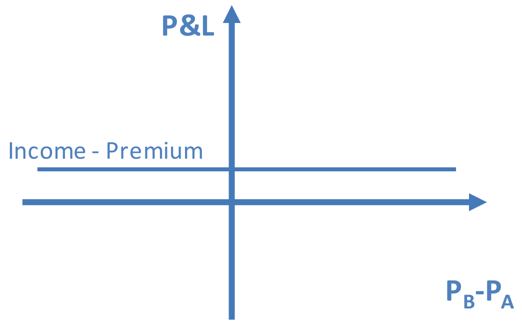


Figure 4: P&L associated to an FTR obligation

Then, by the addition of Figure 1 and Figure 4 we can represent the final P&L of the generator holding an FTR obligation from Market A to Market B.



P&L = Income – Premium

Figure 5: Final P&L for a generator with a cross-zonal position + an FTR obligation

From this it follows that **the generator in A limits not only losses but also profits. Thus, FTRs obligations make the generator insensitive to price spread volatility and impede to benefit from certain price differentials.**

1.2 Trading business

This case shows another kind of possible behavior consisting on the acquisition of transmission rights with the aim to maximize benefits derived from the speculation with price spread made on a basis of market prices forecasts. Nevertheless, traders must not be seen as dangerous participants for the Long-Term market since their participation may contribute to the liquidity of this market and to reliable transmission right pricing. In addition, the experiences in some borders show that this kind of behavior is not only performed by trading companies but also by trading departments of energy companies.

A trader will perform forecasts on the evolution of energy prices in markets A and B. An example where these forecasts provide that in the next year the average P_A will be lower than the average P_B is contemplated.

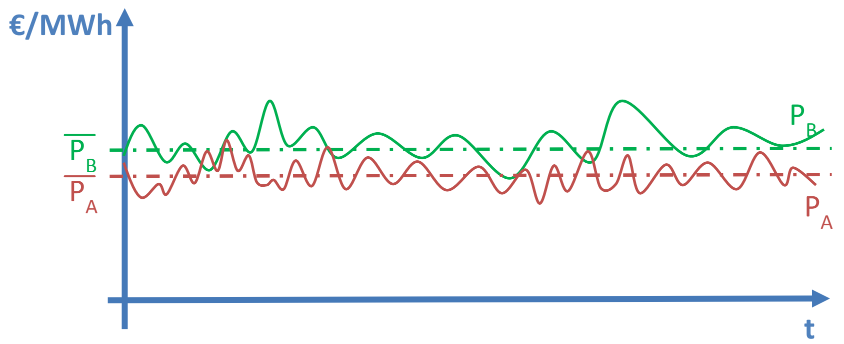
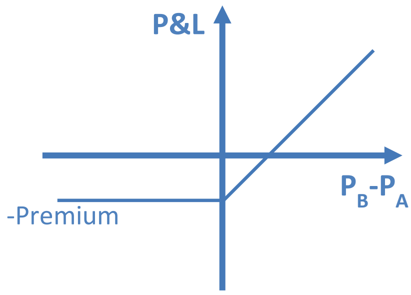


Figure 6: Yearly forecast of prices

In this case, the trader may be interested in buying a yearly **FTR option** from Market A to which entitles him to get paid (P_B - P_A) when positive at a cost (Premium) which will be the marginal price from the FTR auction.



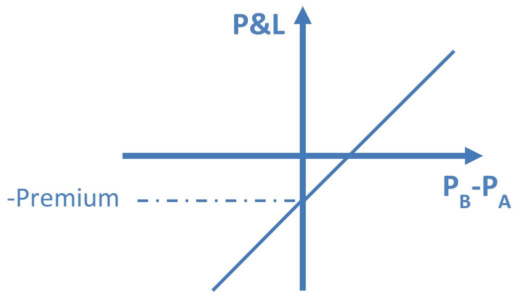
P&L= $(P_B - P_A)$ – Premium ; *if* $P_A < P_B$

P&L= – Premium ; *if* $P_A \geq P_B$

Figure 7: P&L for a trader with an FTR option

Thus, this product will be interesting for the trader as long as his forecast for the evolution of market spread remains greater than the premium he has to pay in order to obtain the FTR.

In the case of an **<u>FTR obligation</u>** from Market A to Market B, the market participant will also be obliged to pay the price spread $P_A - P_B$ when positive. Given this, instead of Figure 7, the P&L associated to an FTR obligation is represented by:



P&L= $(P_B - P_A)$ – Premium

Figure 8: P&L for a trader with an FTR obligation

As it can be seen, **FTRs options provide holders with the possibility of obtaining benefits at a low risk**. On the other hand, **FTR obligations involve higher risk exposure**. These products should therefore be available at lower market prices. Traders willing to accept higher risks might therefore prefer FTR obligations.

2 <u>Economics of transmission rights for the Counterparty</u>

The Counterparty is the entity charged of the auctioning and settlement of transmission rights (typically TSOs or auction offices). It is considered that the counterparty auctions "n" **Financial Transmission Rights options** (or Physical Transmission Rights with UIOSI mechanism but without the right to nominate which is equivalent in terms of economic results) **of 1 MW from zone A to Zone B** and no Financial Transmission Right from Zone B to Zone A. Then, it is commented the particularities of Financial Transmission Rights obligations.

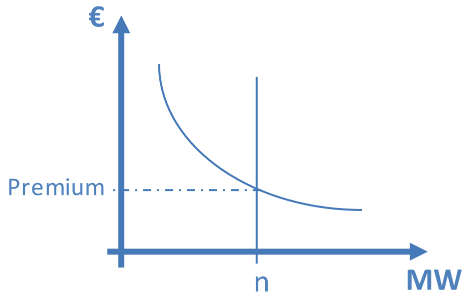


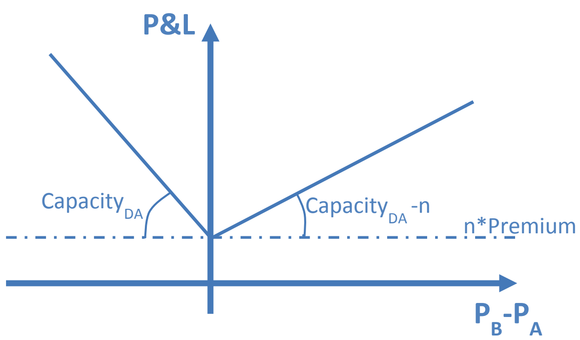
Figure 9: Auction results: marginal price and number of TRs allocated

From this figure it follows that the auctioning entity will have a “fix” income corresponding to the congestion rents associated to the auction (n*Premium).

After day-ahead markets, the auctioning entity will receive a variable income corresponding to the congestion rents dues to the price differences between markets A and B. These congestion rents will be the product of the capacity available to the market coupling ($Capacity_{DA}$) from Market A to Market B and the absolute value of price spread ($Capacity_{DA}*|P_B – P_A|$).

Regarding settlement, the Counterparty will have a payment obligation $n*(P_B – P_A)$ when positive.

Taking into consideration all these incomes and costs, the final P&L for the TSO as the counterparty will be:



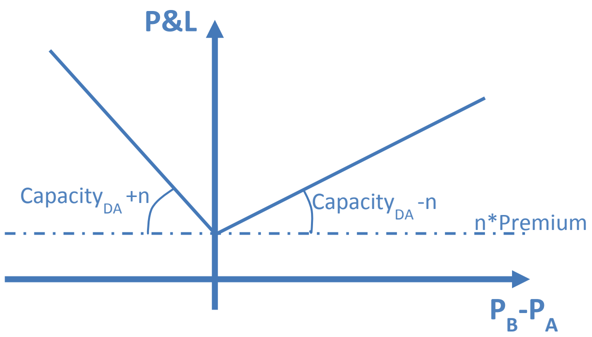
$$P\&L = n * Premium + Capacity_{DA} * |P_B – P_A| \; – n * (P_B – P_A) \quad ; \quad if\ P_A < P_B$$

$$P\&L = n * Premium + Capacity_{DA} * |P_B – P_A| \quad ; \quad if\ P_A \geq P_B$$

Figure 10: Counterparty’s P&L based on final market spread – FTR option

From this figure, we can conclude that, **as long as interconnection capacity available to day-ahead markets is higher than the amount of FTRs options allocated to the market participants, there is no financial risk for the Counterparty**. This is consequence of the fact that the settlement of TRs is based on the congestion rents. In this direction, it is remarkable that **the auctioning of these products do not require a priori the utilization of economic means by the TSO** since the settlement is performed through the congestion rents.

In the case that the auctioning entity auctions **<u>FTRs obligations</u>**, the payment obligation of market participants, n*(P_A – P_B) when positive, will become a variable income for the auctioning entity associated to the settlement of these FTRs.



$$P\&L = n * Premium + Capacity_{DA} * |P_B - P_A| - n * (P_B - P_A) \quad ; \quad if\ P_A < P_B$$

$$P\&L = n * Premium + Capacity_{DA} * |P_B - P_A| + n * (P_B - P_A) \quad ; \quad if\ P_A \geq P_B$$

Figure 11: Counterparty's P&L based on final market spread – FTR obligation

We can also conclude here that, **as long as the interconnection capacity available to day-ahead markets is higher than the amount of FTRs obligations allocated to the market participants, there is no financial risk for the Counterparty**.

APPENDIX 2 FTR OBLIGATIONS – WORKING EXAMPLE CCC

The CCC consists in a 1 MW contract for the price difference between PUN and zonal price allocated by Terna. For each Italian zone annual and monthly CCC are auctioned with the following hourly profile:

- Base load
- Peak load whose underlying is the price difference in the applicable hourly period (7-22) of the working days

In this type of contract the buyer has the following rights/obligations:

For the hours that the zonal price is higher than the PUN, the buyer has the obligation to pay:

CCC = (Pz- PUN)* number of CCC

For the hours that the zonal price is lower than the PUN, the buyer has the right to receive:

CCC = (PUN-Pz)* number of CCC

For example, the selling operator of a bilateral contract would:

	Pay	Receives
$P_z < P_{un}$	$CCT = E_i \cdot (P_{un} - P_z)$	$CCC = Q^{CCC} \cdot (P_{un} - P_z)$
$P_z > P_{un}$	$CCC = Q^{CCC} \cdot (P_z - P_{un})$	$CCT = E_i \cdot (P_z - P_{un})$

Appendix 3 PJM Case Study - Monthly FTR profits by organization type (2010)

Table 8-24 Monthly FTR profits by organization type: Calendar year 2010

	Organization Type		
Month	Physical	Financial	Total
Jan	$171,049,354	($1,214,796)	$169,834,558
Feb	$73,488,400	$972,526	$74,460,927
Mar	($77,576)	($2,155,466)	($2,233,042)
Apr	$27,429,595	$3,747,527	$31,177,122
May	$37,696,949	$4,273,858	$41,970,807
Jun	$112,263,355	$21,073,562	$133,336,918
Jul	$142,003,516	$54,182,662	$196,186,178
Aug	$58,797,492	$7,018,763	$65,816,255
Sep	$83,007,153	$22,306,544	$105,313,697
Oct	$23,554,381	($2,044,975)	$21,509,405
Nov	$30,044,673	$4,095,797	$34,140,470
Dec	$150,293,779	$26,456,212	$176,749,991
Total	$909,551,072	$138,712,214	$1,048,263,286

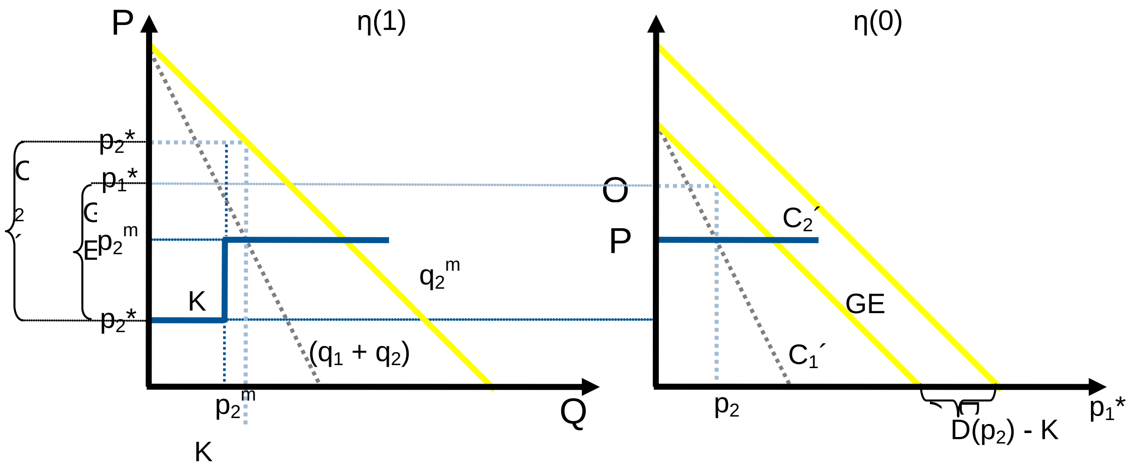
APPENDIX 4 PERCENTAGE OF NOMINATED LONG-TERM CAPACITY (CWE BORDERS/ DEC 10 – SEPT 11)

Percentage of Long Term Capacity Nominated

Auctions		Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Average
BE-FR												
	Monthly	9,07%	4,17%	0,00%	0,13%	0,00%	0,00%	2,34%	0,73%	14,06%	1,71%	2,93%
	Yearly	47,92%	31,94%	33,75%	33,44%	27,50%	27,50%	27,50%	0,56%	0,32%	0,00%	20,95%
BE-NL												
	Monthly	0,00%	0,27%	0,01%	0,13%	16,37%	45,92%	35,81%	26,24%	49,48%	10,85%	16,83%
	Yearly 1	0,00%	1,38%	0,77%	0,13%	2,20%	14,37%	23,68%	25,09%	25,05%	17,40%	10,01%
	Yearly 2	0,00%	16,23%	15,99%	19,92%	52,30%	51,15%	53,69%	58,62%	49,22%	40,46%	32,51%
DE-FR												
	Monthly	12,50%	16,53%	14,23%	12,53%	1,56%	0,00%	0,00%	0,00%	0,00%	0,16%	5,23%
	Yearly	43,69%	15,71%	25,30%	19,35%	0,56%	0,20%	0,00%	0,00%	0,00%	0,21%	9,55%
DE-NL												
	Monthly	12,64%	28,80%	16,69%	12,02%	19,84%	26,37%	0,00%	0,00%	0,00%	0,00%	10,58%
	Yearly 1	47,81%	39,36%	35,04%	33,71%	32,75%	34,19%	31,98%	30,78%	35,06%	27,02%	31,61%
	Yearly 2	63,12%	44,88%	44,27%	42,97%	34,45%	22,43%	31,10%	45,15%	24,45%	21,16%	34,00%
FR-BE												
	Monthly	0,48%	0,63%	26,15%	5,54%	11,46%	17,29%	4,44%	18,64%	27,90%	26,06%	12,60%
	Yearly	0,43%	7,15%	22,72%	22,44%	25,57%	32,08%	23,48%	14,27%	13,06%	19,80%	16,45%
FR-DE												
	Monthly	0,00%	0,94%	2,02%	1,90%	3,82%	22,98%	24,03%	0,00%	38,09%	5,45%	9,02%
	Yearly	2,78%	2,58%	6,31%	7,09%	10,67%	23,16%	31,15%	25,62%	21,67%	8,78%	12,71%
NL-BE												
	Monthly	10,64%	44,35%	2,32%	4,08%	0,00%	0,00%	0,00%	0,00%	0,00%	0,00%	5,58%
	Yearly 1	22,53%	22,29%	22,61%	23,07%	0,00%	0,00%	0,00%	0,00%	0,00%	0,00%	8,23%
	Yearly 2	32,05%	10,56%	14,80%	15,63%	0,00%	0,00%	0,00%	0,00%	0,00%	0,00%	6,64%
NL-DE												
	Monthly	0,00%	0,00%	0,00%	0,53%	0,00%	4,28%	0,00%	0,00%	0,00%	0,00%	0,44%
	Yearly 1	17,19%	0,00%	0,00%	0,13%	0,00%	10,60%	0,00%	0,00%	0,00%	0,07%	2,55%
	Yearly 2	4,14%	0,00%	0,00%	0,13%	0,00%	17,20%	14,46%	0,00%	5,83%	0,70%	3,86%

APPENDIX 5 MARKET POWER

The illustrations below show a region being only connected with one interconnector to other markets. They show the demand curve (D(p2)), the marginal costs curve (C1´and C2´) and the marginal revenue curve (GE). C1´ are the marginal costs for electricity generation which can be imported via the interconnector. C2´ are the marginal costs from local production. The maximum import capacity is K. In the situation shown in a) the monopolist can maximize his profits on the full demand curve thus the price will be p2 and the value of the transmission right (either physical or financial) will be η(1). The illustration b) shows the case where it is not possible for the monopolist to receive any transmission rights. In this case the capacity K will be used by competing traders and the monopolist can only maximize on the residual demand curve (D(p2)-K). With the respective marginal revenue curve this lead to the price p2m and the value of the transmission right will be η(0). η(0) is clearly lower than η(1) what leads to the conclusion that the monopolist has the highest willingness to pay and will thus receive all transmission rights.



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