Financial Transmission Rights – Experiences and Prospects

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Abstract:

This paper discusses the experiences with financial transmission rights (FTRs) so far and the prospects for future developments. Financial transmission rights (FTRs) have been in use for the longest time in the northeastern United States power markets. Here they can provide some conclusive results. Moreover new literature shows that the revenue adequacy test used in issuing FTRs may not hold true for AC power networks. Therefore using the revenue adequacy test in AC networks may cause credit default problems for the independent system operators. Additionally there may be new types of contracts that can substitute FTRs as hedging instruments. Hence we show that these issues may affect the prospects for FTRs.

In continental Europe Italy has introduced the first transmission right-like contracts in Europe and we describe their functionality. Likewise the European Transmission System Operators (ETSO) discusses the introduction of FTRs in the continental European electricity markets. We discuss the obstacles related to that and claim that FTRs in combination with a coordinated congestion method may improve cross-border trade efficiency substantially.

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[1] I have benefited from discussions with Alberto Pototschnig at the Italian ISO (GRTN) and Juan Perez, secretary at the ETSO task force Network Access and Congestion Management.

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1. Transmission pricing

There are different methods for pricing transmission used in practice: locational (nodal) pricing, zonal pricing, and uniform pricing. Locational pricing[2] (Hogan, 1992) maximizes social welfare taking into account transmission constraints and losses, and is performed by a centralized independent system operator (ISO). In this case, the price of electricity at each location equals the marginal cost of providing electricity at that location. Locational pricing is widely used in the US electricity markets. It is used in both the day-ahead and real-time markets. In case of no losses and transmission congestion all prices would equal. Conversely, when losses and congestion are present the prices at the different locations differ. An alternative solution is zonal[3] pricing where several buses are grouped into zones, and the price differentials between the zones are calculated from more or less simplified models. In this case social welfare is reduced and there is lack of price signals for the siting of generators and loads. Hogan (1999) argues that locational prices are based on the principles of economic dispatch and "are self policing and self auditing," while zonal pricing implies deviations from optimal and reliable dispatch. Green (1998) shows that by applying uniform pricing, inferring that location means nothing, welfare is reduced even if transmission constraints are managed through efficient redispatch. This also gives incorrect incentives in the long term.

In a locational pricing system, the congestion fee for transferring electricity between two locations is calculated as the difference in locational prices times the volume transferred. In a zonal pricing system, the fee is calculated as the difference between the zonal prices times the volume transferred. The ISO

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[2] We use the term locational pricing for locational marginal pricing (LMP) in this paper,

[3] In the US, zonal pricing is a term that is commonly used. In the Nordic system area pricing is used for essentially the same concept.

(in a locational pricing system) or the TSO (in a zonal pricing system)[4] receives a surplus during transmission congestion periods and when losses are present, because net payments from loads exceed net payments to generators. The surplus in the locational pricing systems in the US is used in part to pay FTR holders. While the market players can estimate congestion charges ahead of time, the actual congestion charge is only known when the locational or zonal prices are calculated.

In the long run, the most important objective of transmission pricing is to provide the right incentives for the siting of new generation and loads. Additionally transmission network owners should expand the network optimally given the right incentives and compensation. Assuming constant or decreasing returns to scale in the transmission system, the long-run efficiency could consist of a sequence of optimal short-run pricing decisions as pointed out by Hogan (1992). However, the transmission system has typically a nonlinear or lumpy cost function. Therefore, the long-run efficiency may not be attainable in a decentralized market-based system, but obtained through different regulatory mechanisms with central investment decisions (Bjørndal, 2000).

2. Financial transmission rights

This section describes the properties of FTRs, the revenue adequacy test, the awarding and pricing of FTRs and recent issues in the provision of long-term FTRs.

2.1. Properties of FTRs

Because electricity flows according to Kirchoff's laws, it is difficult to define and manage transmission usage. The first transmission capacity definition was a contract path fiction, which then evolved into flow-based paths. However because such a transaction involves the purchasing of several hedges against flowgates (Hogan, 2002a), an alternative approach is the point-to-point definition with implicit flows. Likewise, Joskow and Tirole (2000) have demonstrated analytical superiority of FTRs over physical rights.

[4] Note that this depends on how the TSO is regulated. For example in Norway the TSO has a revenue cap on its revenue.

An FTR gives the holder its share of congestion rents that the regional transmission organization (RTO) or ISO[5] receives during transmission congestion. The amount of issued FTRs is decided ex ante and allocated by the RTO to holders based on preferences and estimates of future transmission capacity. The difference between the congestion rent and payments to FTR holders may be positive, resulting in a surplus to the RTO. The surplus is redistributed to FTR holders and transmission service customers. On the contrary, if payments to FTR holders exceed the congestion rent, the RTO reduces payments proportionally to FTR holders or requires that the transmission owners make up the deficit. The allocation of FTRs typically occurs as an auction, but FTRs may also be allocated to transmission service customers who pay the embedded costs of the transmission system. The design of the auction is decided by the RTO and depends on the market structure. FTRs entitle (or obligate) the holder to the difference in locational prices times the contractual volume (during the settlement period in the day-ahead market). The mathematical formulation for the payoff is:

$$\text{FTR} = Q_{ij}(P_j - P_i) \tag{1}$$

in which P_j is the bus price at location j, P_i is the bus price at location i and Q_{ij} is the directed volume specified for the path from i to j. An FTR can also be divided over multiple points of injection and withdrawal, often called "zonal" or "hub" FTRs. If the contractual volume matches the actual traded volume between two locations, an FTR is a perfect hedge against volatile locational prices.

FTRs can be defined as obligations or options. The obligation type entails the right to receive a payment defined in Equation (1) when the price at the withdrawal location is higher than at the injection location. If the opposite is the case the obligation entails that the holder must pay the price difference times the contract volume as defined in Equation (1). On the other hand an option does not entail any obligation to pay when the price at the withdrawal location is lower than at the injection location.

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[5] From here the term RTO will be used to refer also to ISOs, except when we discuss a specific ISO.

FTRs can take different forms such as point-to-point FTRs and flowgate FTRs both of obligation and option type (Hogan, 2002b). Flowgate FTRs are constraint-by-constraint hedges that give the right to collect payments based on the shadow price associated with a particular transmission constraint (flowgate). Hogan (2002b) argues that point-to-point obligation FTRs have been demonstrated to be the most feasible hedging instrument in practice. However, for point-to-point option FTRs the computational demands are more substantial, but they have been introduced in PJM in 2003. Flowgate rights have been used in California and Texas. Point-to-point obligations can be either balanced or unbalanced, where the balanced type is a perfect hedge against transmission congestion and the unbalanced type is a hedge against losses (represented as a forward sale of energy).

The flowgate rights approach has been proposed by Chao and Peck (1996 and 1997) and is based on a decentralized market design. Stoft (1998) demonstrated that having liquid futures markets for k "Chao-Peck prices"[6] would completely hedge against transmission risk in k flowgates. The flowgate proponents claim that the point-to-point approach does not provide effective hedging instruments because the point-to-point FTR markets may work inefficiently in practice. Oren (1997) argues that they result in price distortions and inefficient dispatch. Therefore, the proponents propose the alternative of using a decentralized congestion management scheme that facilitates the trading of flowgate rights. The idea behind flowgates is that since electricity flows along many parallel paths, it may be natural to associate the payments with the actual electricity flows. Key assumptions include a power system with few flowgates or constraints, known capacity limits at the flowgates and known power transfer distribution factors (PTDFs) that decompose a transaction into the flows over the flowgates. In practice, however, this may not be the case. The physical rights approach has been abandoned and a financial approach has been proposed in the literature (Hogan, 2002b). Baldick (2003) provided a critique of the flowgate implementation. He analyzed various economic and engineering aspects of the flowgate implementation in Texas. He found that the implementation substantively violated the assumptions underlying the commercial transmission model.

[6] Chao-Peck pricing entails explicit congestion pricing. The use of scarce transmission resources is priced, in contrast to locational pricing which prices the use of energy (Stoft, 1998).

In calculating the volume of FTRs that can be issued to transmission customers, the RTO make a model of its power system including FTRs by specifying an FTR as an injection of power at a location and a withdrawal of the same power at another location. Therefore the RTO can associate “counterflows” with FTRs that will make other FTR feasible because flows and “counteflows” net out. Conversely the FTR option does not support “counterflows” and therefore requires a larger share of reserved transmission capacity than the obligation.

A concept that is introduced in some FTR markets is auction revenue rights (ARRs). An ARR is the right to receive the revenues from the sale of an FTR between a defined injection location and a defined withdrawal location in the RTO’s FTR auction. Each ARR is defined in a similar manner as an ordinary FTR such that it direction specific. ARRs are allocated to load serving entities (LSEs) and other that pay the fixed costs of the transmission system. A market player that wants to purchase an FTR can use the proceeds from the ARR to fund the purchase of the FTR.

Similar to the usual practice when trading at a power exchange market players must establish credit limits with the RTO before buying and selling through the RTO auction.

In the US there are states that have implemented retail choice programs, a retail customer is typically allowed to switch it retail energy provider on relatively short notice. Therefore retail energy providers obtain FTRs or ARRs that follow the movement of the retail customers from one retail energy provider to another on a daily basis. The rules are designed to reduce financial risk for the providers and thus increase competition in the retail markets.

2.2. Revenue adequacy

A central issue in the provision of FTRs by a RTO is revenue adequacy. To maintain the credit standing of the RTO who is the counter party, the set of FTRs must satisfy the simultaneous feasibility conditions that are governed by the power system constraints. Revenue adequacy means that the revenue collected with locational prices in the dispatch should at least be equal to the payments to the holders of FTRs in the same period. This can generally be done by ensuring that the implied dispatch from the issued FTRs is physically feasible. If the injected and withdrawn power satisfy the power system constraints, the set of issued FTRs is said to satisfy the simultaneous feasibility test (SFT).

Each time there is a change in the configuration of FTRs, the simultaneous feasibility test must be run to ensure that the transmission system can support the set of issued FTRs. However, because demand varies, it is unlikely that the actual dispatch in the SFT will match the operating point of the simultaneous feasibility test. Therefore the value of the FTR might not accrue to its holder. The interaction among the different FTRs through the simultaneous feasibility test makes the prices and the congestion rents highly interrelated. An efficient FTR market must anticipate not only the uncertainty in transmission prices, but also the shift in the operating point within the feasible region determined by the economic dispatch (Siddiqui et al., 2003).

If the set of FTRs is simultaneously feasible, then they are revenue adequate. This has been demonstrated for lossless networks by Hogan (1992), extended to quadratic losses by Bushnell and Stoft (1996), and further generalized to smooth nonlinear constraints by Hogan (2000). As shown by Philpott and Pritchard (2004) negative locational prices may cause revenue inadequacy. In the general case of an AC or DC power flow formulation, the transmission constraints must be convex to ensure revenue adequacy (O'Neill et al., 2002; Philpott and Pritchard, 2004).

A security-constrained optimal power flow model is utilized and contingency constraints may be numerous. However, practical experience from PJM and New York shows that software can solve this problem. Under a spot market and load equilibrium, revenue adequacy is obtained for point-to-point obligation FTRs, when the implied power flows from these are simultaneously feasible. In the case of obligations, the test is easy to perform, but for options the computational demands are more substantial. Revenue adequacy is the financial counterpart of available transmission capacity (Hogan, 2002b).

Revenue inadequacy may occur when the network topology changes in a way that makes the existing FTRs infeasible. The rules to address this issue are different among the RTOs. One method is to award FTRs to holders on a prorated basis according to the MW volume each holder has. A second method is to provide each FTR holder with a payment equal to what it should receive with revenue adequacy, and then to make up the shortfalls by charging an administrative “up-lift” fee to the market players or transmission owners. These shortfall rules affect the hedging properties of the FTRs since the market players face additional not anticipated expenses ex post.

In case of revenue inadequacy, PJM sets aside surplus congestion revenues each month (i.e., any congestion revenues left over after paying FTR holders) and uses this fund to pay FTR holders when the grid capability is reduced. When the fund runs out, FTR holders are paid a pro-rata share of their actual FTR entitlements. In contrast, New York ISO fully funds FTRs, and assigns any payments not covered through congestion revenues to transmission owners, which can then pass the costs through to their transmission customers through access charges.

Oren et al. (1995) and Oren (2003) argue that the simultaneous feasibility test is too strict. The argument is that because most tradable commodities trade in higher volumes than the underlying physical delivery, it is reasonable to assume that this is also true for FTRs. However, the feasibility condition has importance in allocating new FTRs to investors as demonstrated by Bushnell and Stoft (1997). Oren (2003) proposes that the revenue adequacy requirement should be relaxed to a seasonal or annual accounting, or a value at risk approach.

According to Lesieutre and Hiskens (2005) the feasible set of power injections for the constrained power flow equations is non-convex when practical transmission capacity and bus voltage limits are imposed. The authors prove that in general the feasibility region will not be convex. They examine the consequence of a nonconvex feasibility region on revenue adequacy in FTR markets and note that "close" to convex is not sufficient to provide revenue adequacy. As will be demonstrated in later sections the FTR markets have not proven to be revenue adequate at all times. To cope with these shortfalls, the New York ISO implemented polices in 2003 and 2004 to allocate financial coverage of shortfalls and benefits to transmission owners, and to allow transmission owners to reserve a small portion of transmission from TCC auctions to try to avoid congestion revenue shortfalls (Lesieutre and Hiskens, 2005). Additionally it might be that the actual network (topology) may differ from that assumed in the simultaneous feasibility test. Lesieutre and Hiskens suggest that the use of an AC power flow (as is used by New York ISO) may increase the effect of unplanned line outages to create congestion revenue shortfalls, or be the cause of such shortfalls. They also express a concern that unproven assumptions about system (convexity) properties may be used to assert other properties (revenue adequacy) that are used to justify policy. Since commencing operation of FTR markets, RTOs have appropriately implemented policies to handle situations in which congestion revenues fall short of FTR obligations. As market designs evolve and improve, it is reasonable to expect that congestion management methods will tend to employ the most accurate models possible, and DC power flows will give way to more accurate AC power flow models. Unfortunately, as these more detailed models gain wider acceptance, it will be impossible to prove revenue adequacy or expect it in practice. Adoption of new FTR mechanisms will need to be accompanied by policies for accommodating congestion revenue shortfalls.

2.3. Awarding and pricing of financial transmission rights

FTRs can be awarded in different ways (Lyons et al., 2002). First, they can be given to those who invest in transmission lines. Second, FTRs can be provided to load-serving entities[7] and others that pay fixed cost transmission rates, either through direct allocation or through an auction process in which the LSE is allocated ARRs[8] that can be used to purchase FTRs. For other market players there needs to be eligibility requirements for FTR ownership in the existing transmission system and in the secondary markets. The implemented solution depends on the market design and the decisions made in that market. FTRs for existing transmission capacity can be allocated in a number of different ways such as based on existing transmission rights or agreements (historical use and entitlements), auctioned off, or so that their benefits offset the redistribution of economic rents arising from tariff reforms. According to Federal Energy Regulatory commission (FERC, 2005) there are two general approaches for allocation of FTRs or ARRs to existing transmission capacity:

- Direct allocation of FTRs by using an administrative process including eligibility criteria to directly allocate FTRs to LSEs on annual basis. LSEs with network rights are typically eligible to receive FTRs between their network resources and network loads. Players with point-to-point FTRs are eligible to receive FTRs for their corresponding injection and withdrawal locations specified in their rights.

[7] An entity that serves retail load.

[8] An ARR is defined as the right to collect revenues from the subsequent FTR auction. The collected revenue equal the contract volume times the market clearing prices. An ARR may match an FTR exactly but it does need to.

- Direct allocation of ARRs with an FTR auction by using an administrative process to directly allocate ARRs which then allows the players subsequently to choose how use their ARR in an FTR auction. A player receiving ARRs is not limited to purchasing FTRs that correspond to the player's ARR points, but it may purchase FTRs for other transactions or schedules or just for trading purposes.

The revenues from an auction can be allocated to the transmission owners. In California transmission owners use them to pay off their transmission investments, and in New York they are used to reduce the transmission service charge.

The awarding of point-to-point obligation FTRs usually takes place in uniform, second price auctions, where the benefit function of the buyer or seller is maximized. The benefit function is assumed to be concave and differentiable and is optimized subject to all relevant system constraints. The auction determines the allocated amount of FTRs to market players and market clearing-prices. It is also a mechanism for reconfiguration of FTRs. The buyers and sellers can offer FTRs between any two locations or aggregations of locations. A bid is defined as the willingness-to-pay for the injection of a MW at a location and the withdrawal of that volume at another location. Conversely an offer is defined as the minimum sale price for an FTR. For any pair of injection and withdrawal locations, the auction clears at a single price and the winning bids all pay the price bid by the second highest bid. The market clearing prices in the auction do not necessarily equal the bid and offer prices and are limited by a lower cap equal to winning offers and an upper cap equal to the winning bids. Furthermore the type of FTR: obligation or option has an impact on the prices. The option reserves more of the transmission capacity and a corresponding lower volume than the obligation. Therefore it results in a higher market-clearing price for the option than the obligation.

To further stimulate reconfiguration and liquidity FTRs can be traded in secondary markets. It may happen that an FTR between two locations is non-existent. Then it may be possible to combine other FTRs to synthetically construct the non-existent FTR. FTRs may have duration from months to years.

Siddiqui et al. (2003) identify two issues that are important in evaluating financial hedging instruments. The first issue is how good the hedge is. The second issue is how efficient the market is. Important data in this regard are FTR prices and volumes (liquidity). An FTR is also a forward contract since it hedges against future uncertain locational prices. The market price of the forward contract should reflect the value of the underlying risky cash flow with a proper risk premium. According to Energy Security Analysis (2001) the price level of a forward contract is driven by the volatility of prices, the number of competitors in the market, and the credit standing of the counterparties. Illiquid markets will result in higher premiums compared to liquid markets.

A proper relationship between the forward price and the underlying asset is achieved through arbitrage. This may be more difficult when dealing with FTRs. The large number of possible FTRs gives relatively low liquidity. There are few secondary markets that enable reconfiguration and reselling. The issuer of FTRs is usually an RTO. The linkage between the simultaneous feasibility test and FTR revenue sufficiency is an important factor in preserving the quality and value and amount of the FTR hedges. If the test is not met, revenues may be insufficient to cover payments to FTR holders.

Siddiqui et al. (2003) study the prices of FTRs in the New York market and find that the prices do not reflect the congestion rents for large exposure hedges and over large distances, and that the FTR holders pay excessive risk premiums. The authors argue that this may be due to the way the FTRs are defined with fixed capacity over a fixed period and high transaction costs for disaggregating them in the secondary market. Market players therefore consistently predict transmission congestion incorrectly for all other hedges other than the small and straightforward hedges. Also the large number of possible FTRs decreases price discovery. Pricing of FTRs is based on anticipated and feasible congestion patterns which may not be realized in the actual dispatch. This may make FTRs mis-priced. However, the pricing of FTRs may be symptomatic of an immature market. Also, arbitrage of electricity prices may be impossible because of illiquidity, risk aversion and regulatory risks (Siddiqui et al., 2003). Furthermore Adamson and Englander (2005) point out that the analysis suffers from methodological shortcomings because it relies on ordinary least squares estimation. This estimation is inefficient in the presence of autocorrelation, which is observed between auction and spot prices. Another problem in using ordinary least squares estimation is heteroscedasticity, which is also observed for auction and spot prices.

Adamson and Englander (2005) also studied the prices of FTRs in the New York market. They used data from monthly FTR auctions and time series ARCH-ARMA (autoregressive conditional heteroscedasticity - autoregressive moving average) models to postulate how clearing prices for FTRs are formed and the resulting implications for market efficiency. The analysis confirmed other studies suggesting that these auctions remain highly inefficient, even after allowing for risk aversion among bidders in the auctions.

2.4. Recent issues in the provision of long-term FTRs

Currently when a market player invests in transmission expansion, the RTO will allocate to the market player the amount of FTRs corresponding to new capacity created. The specific rules vary among the RTOs and the FTRs typically have longer duration than the FTRs allocated to the existing capacity. The market player may have the option to decline an award of FTRs with negative value and it may be able to return FTRs if their future value become negative.

Currently, the longest term FTR offered in any of the RTO or ISO markets is one year (FERC, 2005). FERC (2005) seeks in its "Notice inviting comments on establishing long-term transmission rights in markets with locational pricing" comments to the following issues:

- Are long-term FTRs needed more by certain types of market players or in certain regional markets?
- What specific impediments or problems must be addressed when introducing long-term FTRs?
- The plans of specific RTOs and ISOs to address long-term transmission rights.

FERC (2005) points out that some market players have concerns that sufficient FTRs may not be available each year to adequately cover their congestion cost exposure. They argue that the combination of potentially volatile congestion costs, variability in the annual allocation, and the inability to secure a known volume of FTRs for multiple years introduces too much uncertainty into operation and investment considerations. Therefore some market players want the ability to obtain long-term FTRs at a fixed price.

Providing such long-term FTRs presents challenges. One such challenge is that the actual grid conditions are different than those anticipated under the provision of FTR, the RTO could collect insufficient congestion revenues to pay the FTR holders. Decisions must then be made regarding who will bear the revenue shortfall. As might be expected, the longer the duration of the FTR, the greater the probability that grid conditions will be different than forecasted.

Market players have shown interest in long-term FTR for a number of reasons. The first reason is that market players with long-term generation resource commitments and load experience locational pricing uncertainty, which increase the transmission congestion risk. Therefore they believe that long-term FTRs (longer than one year) will let them hedge the risk. Conversely they mean that annual long-term FTRs create greater price risk because of uncertainty in the allocation.

The second reason is the interest among market players that invest in new generation to serve load. They want to receive long-term FTRs with a lifetime equal to the financing horizon or the life asset so they can hedge the uncertainty in future generation profit. Therefore they view this as important for the company's credit rating or ability to undertake project financing.

According to FERC (2005) not all market players agree in the need for long-term FTRs or the design of them. However as long as the long-term FTRs do not create significant equity issues most of the market players that FERC consulted did not oppose to them.

Prior to the implementation of RTO markets (locational prices and FTRs), transmission service for customers in those regions was governed by Open Access Transmission Tariff (OATT). Under the OATT, there were two types of transmission service – network integration transmission service (network service), which was a long-term firm transmission service, and point-to-point transmission service, which could be provided on a firm or non-firm basis and on a long-term (one year or longer) or short-term basis. Long-term firm transmission customers had the right to continue to take transmission service from the transmission provider when the contract expired, rolled over or was renewed (rollover right). According to FERC, OATT transmission service, once obtained, appears to provide better long-term price certainty than the current RTO transmission service. However, congestion management could be inefficient and network transmission rights were not easily traded and reconfigured, such that those who value them most highly can obtain them from willing sellers. The RTO transmission service greatly improves access, provides price-based congestion management that is generally efficient, and allows auctions and secondary markets for trade in transmission rights that are increasingly flexible in terms of locations and time periods covered. On the other hand, there are concerns that FTR allocations do not always offer long-term price stability, that is, adequate coverage of congestion charges. According to FERC the policy issue is thus whether parties should be allowed to revert to some version of the prior OATT service within the RTO markets with locational prices and FTRs or whether the FTR model can be modified to provide the type of congestion cost coverage that such parties seek.

FERC (2005) notes that the most important impediments to the introduction of long-term FTRs are:

- FTRs are allocated under dispatches that are similar to the operating point of the simultaneous feasibility test for the year ahead. Uncertainty about the future network topology and generation resources makes it difficult for the RTO to forecast accurately the available transmission capacity many years into the future.
- Transmission congestion prices and patterns in RTO markets have been difficult to predict and can change dramatically year to year.
- There are possibilities for significant financial gains or losses associated with FTRs because of the difficulty in valuing them and this can affect the credit rating of market players that own long-term FTRs.
- In RTO regions with retail choice states, LSEs facing competition typically do not seek transmission rights beyond the duration of their energy contracts. New contracts could require a different set of FTRs. By tying up valuable hedging instruments over many years, allocating long-term transmission rights could become a barrier to entry.
- Market players are concerned that long-term FTRs will be less liquid than annual or shorter term FTRs, and thus result in a less efficient market for congestion hedges.

Regarding the market design issues FERC has the following comments:

- The eligibility criteria: are long-term FTRs available to all market players currently eligible for ARRs or FTRs in the RTO system or whether priority is given to some participants on the basis of historical contracts or resource usage. Alternatively FTRs could be made available not based on historical contracts but rather to adopt a basis for all RTO players to qualify. A second issue regarding eligibility is whether the awarding of FTRs should be based on credit rating for the duration of the long-term FTR.

- The duration of the long-term FTRs: the preference for the duration of the long-term FTRs is likely to vary. LSEs may have preference of several decades. Conversely, LSEs involved in retail competition may have a preference for a few years because they need greater flexibility when the location of the load changes. Other market players may have purchased FTRs to maximize their revenue and therefore want these to match their expectations about future congestion charges. Likewise the long-term FTRs may be differentiated between on-peak and off-peak hours.
- The design of the FTRs - obligations or options; Obligations involve payouts for the owner when the location price is higher at the injection location than at the withdrawal location. Conversely, options do not involve these payouts. The options are therefore less risky but they support a smaller contract volume than the obligations and they are more expensive than FTR obligations.
- How the rights are initially awarded (allocation or auction): For long-term FTRs there are currently two basic approaches that would be used to award them: (1) direct allocation of FTRs where they are allocated based on eligibility requirements, or (2) direct allocation of ARRs followed by auction of FTRs where liquidity is promoted by bringing more sellers into the market. For the advantages and disadvantages of each approach we refer the reader to FERC (2005).
- Rules for FTR payments when RTO is not revenue adequate: Rules are needed to determine whether and how much FTR holders are paid when there is revenue inadequacy. Design of different payment rules may create financial contracts with different properties and associated implications for cost assignment.

Another issue in the provision of long-term FTRs is infrastructure financing. According to FERC (2005) transmission dependent utilities claim that unavailability of long-term FTRs affect their possibility to finance new generation projects located remotely from the load.

If these utilities finance investments by borrowing against the firm's overall assets and revenues, the lack of long-term FTRs could have an impact on the overall credit rating of the utility. This could affect the utility's ability to invest in new generation. Conversely, in project financing undertaken by merchant investors the projected sales revenues are used to secure financing. Merchant generators typically enter into contract with delivery at the injection point. Therefore they are unaffected by the congestion risks. Furthermore the regulatory risks are perceived as significant among investors in the electricity business, because the market rules have changed sufficiently frequently in the past. Therefore investors will not see the revenues from their investments as guaranteed.

FERC (2005) points out that there are alternatives to FTRs in hedging the congestion risk. Some transmission users have expressed interest in physical transmission scheduling rights similar to OATT rights. The generic design includes that transmission customers pay an RTO access rights, and as long as they remain within their reserved transmission usage they would be hedged against the transmission congestion risk. However in the presence of congestion these customers could be subject to physical curtailment. As an alternative there could be rules specifying ahead the redispatch charges that such a customers would be willing to pay. The design of the physical scheduling rights differ in that they would not give a payment when transmission is not scheduled and they do not involve payment obligations after the initial purchase. The physical scheduling rights could be applied to the entire market or a subset of this.

Under an OATT-type physical scheduling right regime there needs to be an allocation of transmission capacity to parties that nominate for FTRs. One approach is to let the RTO reserve some percentage of the transmission capacity that would be used for scheduling entities with the pre-RTO scheduling rights when allocating FTR. However, this may be an equity issue in redispacth because market players have different costs and incentives. Also it would support a lower volume of FTRs because part of the capacity is reserved for the physical scheduling rights.

In the second approach, the transmission capacity needed for the customer’s physical scheduling rights is not excluded from the transmission capacity available for FTRs. This method avoids the disadvantages of the first approach. However, if the transmission customer is granted physical scheduling rights, some entity (possibly the transmission owner) must take on the obligation to pay congestion costs and possibly hold FTRs. This approach may require an additional amount paid by the holder of the FTR to the purely physical customer to finance the risk undertaken.

3. The United States FTR experience

Each market in the US uses slightly different terms for FTRs. The fundamental properties of the FTRs described in section 2.1 remains the same but the difference in how the rules are designed can affect the valuation of the FTRs. The description of the different markets is mainly based on FERC (2005).

In PJM (Pennsylvania, New Jersey and Maryland), FTRs are called fixed transmission rights, in New York transmission congestion contracts (TCCs), in California firm transmission rights and in New England and in the Midwest ISO region financial transmission rights. In this paper we use the generic term FTR to describe all these contracts.

FTRs have been used in the PJM Interconnection since April 1, 1998, in New York since September 1, 1999, in California since January 1, 2000 (auctioned off in September, 1999), in New England since March 1, 2003 and in the Midwest ISO region April 1, 2005. They were also introduced in Texas in February 15, 2002. PJM also introduced FTR options in 2003.

In this section we summarize the various FTR markets in the US with respect to the rules for allocating, auctioning and trading based on FERC (2005). Most of these markets are based on locational pricing in the day-ahead market. The most important exception is the California ISO, which currently employs zonal pricing and zone-to-country FTRs. However, the redesigned California ISO market will implement locational pricing and associated FTRs.

3.1. PJM RTO

From April 1, 1999 to 2003 obligations FTRs with annual duration were allocated directly to transmission customers while the remaining amount could be auctioned off to point-to-point customers. The customers did not need to take the FTRs allocated to them. In 2003 a monthly auction was established for remaining FTRs, reconfiguration, and trade of allocated FTRs. On June 1, 2003, PJM introduced ARRs that are allocated to customers with network resource integration service up to their total annual load and to customers with firm point-to-point service up to the volume specified in the transmission reservation and for the period of the reservation. The ARR allocation is implemented in two stages. In Stage 1, LSEs are eligible to nominate ARRs from generation resources that historically served load in each transmission zone. In Stage 2, market players are not restricted to historical resources. There are four rounds in which 25 percent of the remaining transmission capacity is allocated in each round. Participants can assign priorities, from 1 to 4, for the ARRs nominated in these rounds. They can also view the results of each round before proceeding to the next round. Holders of ARRs can convert them to the FTRs as explained in section 2.1. Annual auction revenues are distributed to holders of ARRs. ARR revenues may be prorated. The annual auction settlements and the corresponding ARR settlements take place on a monthly basis.

PJM conducts both annual and monthly FTR auctions. In the annual auction, FTRs with duration equal to one year are traded. These can be obligations or options and can be specified for the daily off-peak hours, the daily peak hours or all 24 hours. The annual auction has four rounds in each of which 25 percent of the feasible transmission capacity is made available. A participant that purchases an FTR in one round may offer it for sale in subsequent rounds. Monthly auctions are conducted for any residual transmission capability not sold through the annual auctions for FTRs offered for sale. The monthly auctions sell monthly FTRs.

Incremental, multi-year ARRs are assigned for transmission expansions associated with generator interconnections and merchant transmission projects. The duration of the ARRs is thirty years or the life of the facility or upgrade, whichever is less. The ARRs are awarded in three rounds in each of which the party requesting the rights can nominate a different point-to-point path if it chooses. The ARRs nominated by the third round become final. Market participants awarded such multi-year ARRs have a one-time option to switch to an annual allocation of their eligible ARRs. They may also turn back any multi-year rights that they no longer desire to hold, as long as this does not affect the feasibility of the ARRs of other parties.

Figure 1 shows the development over time of the FTR credit in the PJM market in the period April 1998 – December 2004. The credit has varied from 90.4 percent to 100 percent. The monthly average is 95.1 percent. On average the credits therefore have been de-rated.

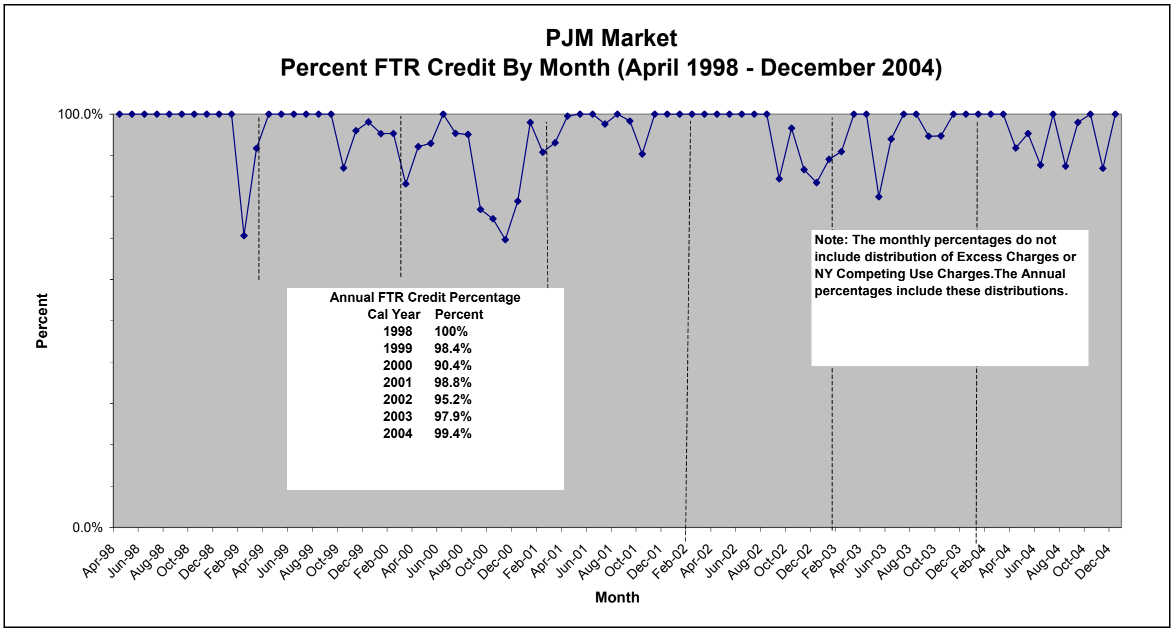

Figure 1. Percent FTR credit by month in the PJM market in the period April 1998- December 2004 (source: PJM interconnection).

3.2. New York ISO (NYISO)

The New York ISO (NYISO) was the first organized market to introduce an annual auction for FTRs. Before conduction the first auction in September 1999 several existing transmission right owners had the option to convert their rights to grandfathered FTRs or to keep their grandfathered rights. Transmission owners with obligations to serve load were allocated existing transmission capacity for native load (ETCNL) rights. Before each bi-annual initial auction, a portion of these ETCNL rights can be converted to ETCNL FTRs (6-month FTRs). ETCNL rights that are not converted are sold in the initial auctions and work like ARRs in that they entitle the owner to the revenues resulting from the sale of the corresponding FTRs. Remaining transmission capacity was allocated to transmission owners as original residual capacity. In advance of each initial (bi-annual) auction residual capacity reservation rights (RCRRs) were allocated to transmission owners subject to existing grandfathered rights, ETCNL rights, and valid FTRs. Transmission owners can then convert a portion of their RCRRs to 6-month FTRs and sell the remaining rights into the initial auction.

The New York ISO conducts a number of auctions each year to facilitate the liquidity of the FTR market. At initial auctions, held twice a year, the NYISO releases FTRs, including non-converted

ETCNL rights, original residual capacity and RCRRs, as well as expired grandfathered rights, for sale in two stages of multi-round auctions. During the first stage, a certain percentage of all the FTRs for sale are released in each of the four rounds. The second stage allows FTR holders to resell rights they purchased through the first stage. Currently the effective period of the auctioned FTRs is determined by the ISO, and is either 6 months or one-year. At the discretion of the New York ISO, multi-year FTRs with duration up to five years are offered. The price is determined by the lowest winning bid for a particular FTR point-to-point pair in a specific round. The New York ISO also holds monthly reconfiguration auctions in which FTR holders can offer to sell their FTRs for the subsequent month.

Market players who invest in transmission expansion are entitled to 20-year expansion FTRs, commencing when the new transmission facility begins operation. The expansion FTRs consist of only the new FTRs made feasible as a result of the transmission expansion.

3.3. ISO New England

The ISO New England market includes locational pricing, ARRs and an FTR auction. The ARR methodology is unique to New England. ARRs are allocated monthly first to the entities that pay for transmission upgrades that increase transfer capability on the NEPOOL transmission system, making possible the award of additional FTRs in the FTR auction. The remaining auction revenues are allocated to each congestion-paying LSE in proportion to its load ratio share. Any ARRs allocated that have negative values in the FTR auctions are eliminated. The remaining ARRs are reduced proportionally until a solution is reached in which all the ARRs are simultaneously feasible given the other rights, including the excepted transactions (grandfathered contracts), NEMA (Northeast Massachusetts) rights, and quality upgrade awards. The excepted transactions consist primarily of transmission agreements for certain point-to-point wheeling transactions across or out of the network and are assigned either to entities serving load to which energy is delivered or to entities making an external sale. Excepted transactions are given the option to receive ARRs from the generator to the specified load location. To date, about 0.5 percent of the ARR revenues have gone to entities with rights associated with excepted transactions. Generally, an entity receiving ARR revenues does not know its ARR position before the FTR auctions are held, as the value of its ARR allocation is contingent on the MW amounts resulting from the four stage ARR allocation process and the auction clearing prices associated with the ARR paths. ARRs are made available on a long-term basis to holders of excepted transactions and NEMA rights.

Auction revenues are made available on a long-term basis to entities that invest in transmission upgrades that increase the transmission capacity of the NEPOOL transmission system. These are referred to as "qualified upgrade awards" (QUAs). Qualified upgrades, which normally are new expansions to the transmission system, are awarded rights to receive FTR auction revenues. The FTR bids and revenues are first determined with the upgrade and then without each upgrade. The difference in revenues between the two (which can be interpreted as the value the upgrade brings to the system) is awarded to those entities, which provided the upgrade. Qualified upgrade payments are made as long as the entity pays for the upgrade, or for the life of the asset, whichever is shorter. To date, approximately 1.5 percent of the total FTR revenues have been assigned to qualified upgrades.

New England conducts FTR auctions for peak and off-peak periods. Fifty percent of the total transmission capacity is made available in an annual month auction, and the residual transmission is sold in monthly auctions.

Table 1 shows the percent positive allocation paid the FTR holders (i.e. credit) in the New England market in 2004. The monthly allocation paid has varied between 69 percent and 100 percent.

Month	Percent Positive Allocation Paid
Jan.	91%
Feb.	94%
Mar.	85%
Apr.	79%
May	78%
Jun.	95%
Jul.	100%
Aug.	100%
Sep.	100%
Oct.	100%
Nov.	69%
Dec.	100%

Table 1. Percent FTR credit by month in the New England market in 2004 (source: New England ISO).

3.4. Midwest ISO (MISO)

Introduction of FTRs in the Midwest region was a controversial issue, partly because of the conversion of existing pre-OATT and OATT transmission rights. Market players wanted to hold FTRs that would be sufficient to hedge their long-term contracts or investments. A larger share of the transmission capacity than in other RTO region was also reserved for grandfathered rights (FERC, 2005).

FTRs are allocated directly to transmission customers. In the discussions about the market design, different issues were proposed such as assignment of FTRs based on historical use of network resources as well as voluntary nomination of FTRs by market players between their eligible points of injection and withdrawal. The Commission approved a "compromise proposal" for the annual allocation, developed in consultation with market players and with substantial input from the Organization of Midwest States (OMS). In this compromise players voluntarily nominate FTRs between their eligible points of delivery and receipt while all players remain eligible to receive a full allocation of nominated FTRs from resources they use to serve base load (with criteria to determine base load). To ensure that base load FTRs are made feasible when a full allocation is not obtained, counterflow FTRs are allocated (to players providing existing transmission service). FTRs can be nominated from network resources based on the forecast peak load served under network integration transmission service, and from the points of injection and withdrawal in point-to-point transmission service of annual duration or longer. The maximum volume eligible for nomination is the sum of these existing entitlements for network service and the total volume in each point-to-point service. The FTR allocation process occurs over four successive and cumulative tiers. In each tier, a market player is allowed to nominate up to a share of its maximum nomination eligibility less the FTRs awarded in the prior tier. The cumulative tier factors are: tier I, 35 percent; tier II, 50 percent; tier III, 75 percent; and tier IV, 100 percent. For a period of five years following the start of the day 2 market, any eligible FTRs that were prorated in the first two tiers are eligible to be restored. The eligibility requirement is that, if the nominated FTR is from a network resource with a defined average historical capacity factor of at least 70 percent, and if the nominated FTR is to convert existing point-to-point service, that service has a historical scheduling factor of at least 70 percent. To make feasible the prorated FTRs, the Midwest ISO will define counterflow FTRs sufficient to make the eligible nominated FTRs simultaneously feasible. Counterflow FTRs are defined as eligible base-load FTRs that were either not nominated by a market player or not awarded in the first two tiers, but if assigned, would provide counterflow in the FTR model for restoration of other nominated FTRs. The Midwest ISO will choose the minimal set of counterflow FTRs needed for restoration. The counterflow FTRs are allocated directly to the market player that was eligible to nominate them. They are settled like ordinary FTRs, except in the event of a unit outage, in which case they are not settled. When shortfall in congestion revenues occur the payments to FTR holders are reduced on a pro-rata basis. Market players in load pockets called “narrow constrained areas” (NCAs) that are defined as locations in which imports were affected by a transmission constraint for 500 hours or more in the preceding year, receive sufficient FTRs to cover their existing firm transmission contracts for imports for a five year period.

MISO directly allocates incremental FTRs for network upgrades under its current transmission tariff. Entities can choose FTR volume from any set of injection and withdrawal locations in the transmission network that reflects the incremental capacity that has been made available subject to feasibility with the remaining FTRs. The maximum duration of these FTRs is one year. In each following allocation, the FTRs are reevaluated based on any incremental transmission capacity changes created by the expansion. When monthly differences in the incremental capacity occur, the MISO may issue some incremental FTRs specified for the months where the capacity is available. When multiple market players pay for transmission expansion, FTRs are awarded in proportion to their financial share of the expansion costs, which they preferably should have agreed on beforehand.

In the future there will be several changes in the Midwest ISO transmission markets. First, after five years, the provisions for non-voluntary assignment of counterflow FTRs will end. Second, Midwest ISO intends to begin development of ARRs after the start of the day two markets. Third, the Commission has required Midwest ISO to begin planning for allocation of long-term FTRs.

3.5. California ISO (CAISO)

All FTRs in California have been options, not obligations. In the definition of FTRs, the CAISO has made available 100 percent of available transmission capacity at a 99-percentile availability level in each direction of an interface, corrected for grandfathered existing contracts. As grandfathered contracts end, the volume of available FTRs is expected to increase. Until lately, no FTRs were available on Path 15, one of the major constraints within the CAISO.

The CAISO has conducted annual auctions for FTRs since 1999, with FTR durations of one year and in some cases 13 or 14 months. All auctions had multiple rounds with FTRs defined on inter-zonal interfaces and on interties with external areas. There have been roughly 10000 MW of FTRs sold annually amounting to annual auction revenues close to $100 million in recent years. Auction revenues are attributed to transmission owners who use them to compensate transmission access charges.

The CAISO is currently redesigning its markets to include locational pricing where FTRs will be closer to the point-to-point design used by eastern RTOs. The LMP market is currently expected to start in 2007. In the new market, FTR allocations will be for 12 months of monthly FTR volumes, with both peak-hour and off-peak-hour varieties and potentially different volumes for each month to allow parties to hedge time-of-use and seasonal variation in expected congestion costs. For the purpose of the annual allocation, the CAISO would limit total volumes to 75 percent of available transmission capacity. In addition, there would be monthly "true-up" allocation or auction processes, conducted before the start of each month, in which the remaining transmission capacity could be allocated to players based on their revised estimates of their needs and accounting for planned transmission outages. Long-term FTRs are likely to be considered after the start of the new market.

4. The Baldick proposal for financial transmission rights

Baldick (2005) notes that the RTO does not provide market for forward contracting of both transmission and energy simultaneously. He therefore proposes to define a new transmission property right that does not require the RTO to be the issuer of FTRs and devolves the risk to the transmission owner. He names this new contract “contract for differences of differences.” The contract allows for forward contracting of both energy and transmission simultaneously through a single exchange. In addition to being a hedging instrument, the contract supports new transmission projects or upgrading. A centralized reconfiguration auction is needed when the transmission customers have alternative preferences for FTRs. Conversely, purely financial contracts do not require any centralized reconfiguration auction.

The design of the contracts for differences of differences builds on the work of Gribik et al. (2002 and 2005). The contracts remunerate transmission based on flows and locational prices by paying the line for the energy it supplies to the rest of the system at the locational prices and letting it pay for the energy it takes from rest of the system at the locational prices. The contracts distribute the congestion rent directly to lines and guarantees revenue adequacy for the RTO under all dispatch conditions.

Contracts for differences of differences (CFDDs) are analogous to contracts for differences in energy but are contracts to hedge deviations from strike price for differences in locational prices. The CFDDs are financial contracts between transmission owner and customers and pay the product of a contract volume times the difference between a strike price and the difference between in locational prices between two nominated buses. Furthermore CFDDs do not require any reconfiguration auction. The CFDDs can be flexibly defined without restriction of the simultaneous feasibility test and the RTO is revenue neutral under all dispatch conditions. Table 2 shows that by defining the new CFDD there is also an underlying revenue stream for the transmission assets. Baldick proposes that the contract should be defined based on precontingency flows.[9]

Proposed energy and transmission rights			
Asset:	Product:	Underlying revenue stream	Financial instrument
Generation	Energy	Energy times locational prices	Contract for differences and variations
Transmission	Energy Transport	Energy times locational price differences	Contracts for differences of differences

Table 2. Comparison of current implementations of energy and transmission markets.

We use an example from Baldick (2005) to illustrate the properties of the CFDDs. It is a simple two-bus system, with two buses, and a corridor of three lines joining the buses, each having the same admittance. However, the lines have different capacities of C_1 = 50 MW, C_2= 60 MW, and C_3 = 70 MW, respectively. For simplicity, it is assumed that these capacities apply in both normal and emergency conditions. The situation is illustrated in Figure 2. There is a generator at bus 1 that offers

[9] Flows that take into account security constraints.

its energy at $20/MWh and a generator at bus 2 that offers its energy at $30/MWh. Capacity constraints on the generators are ignored. There is 150 MW of demand at bus 2. In the illustrated example each line flow is 50 MW. Each line is then remunerated with an amount that equals the energy flow times the locational price (LMP) difference: 50 MW · (30$/MWh-20$/MWh)=500$.

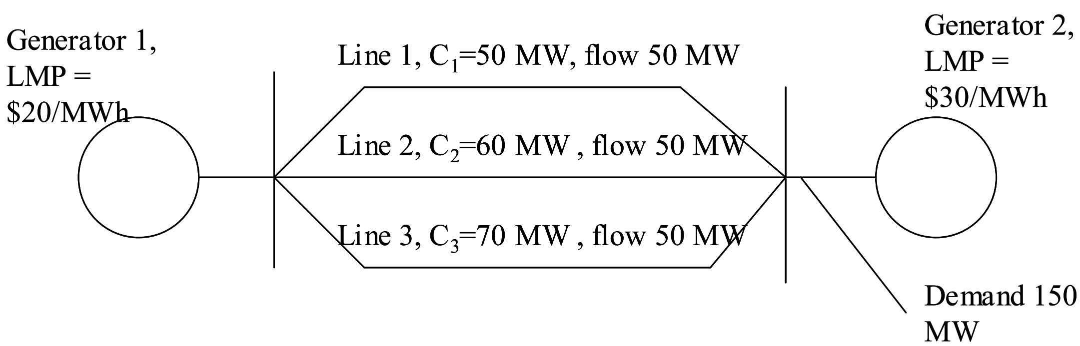

Figure 2. Two node, three network.

5. Congestion hedging instruments in Europe

This section describes the status regarding FTRs in Europe and in more detail the experience from the Italian and Nordic markets with congestion hedging instruments.

5.1. FTRs in Europe

There is no practical experience in Europe with pure FTRs as defined in the US. Furthermore no countries in Europe use full locational pricing. The usual practice is zonal pricing or single area pricing. ETSO (European Transmission System Operators) discusses FTRs in its taskforce group Network Access and Congestion Management Group (Perez, 2005). Most countries in Europe use explicit auctions to auction off cross-border transmission capacity while the Nordic region uses implicit auctions (market splitting). Explicit auction create inefficiencies in the pricing of transmission capacity because energy and transmission capacity are traded separately. In implicit auctions energy and transmission capacity are traded simultaneously and thus create less uncertainty in the anticipation of the pricing.

However ETSO and EuroPex (Association of European Power Exchanges) discuss the introduction of the concept flow based market coupling (FMC) in the continental European market (ETSO-EuroPex, 2004). The concept evolved from the Nordic market splitting method. FMC is a combination of the ETSO's flow based modeling concept and the EuroPEX's decentralized market coupling concept. The objective of FMC is to coordinate market operation at the day-head stage. FMC assumes that the European power system can be operated as a number of single price regions linked through market coupling. The Nordic market splitting is conceptually simpler as it does not consider loop flows and is integrated in that energy and transmission capacity is traded simultaneously. Conversely, the FMC approach does not have an integrated market from the beginning, only independent markets. FMC includes two clearing processes. First the energy market clearing where the power exchanges in each region establishes a price dependent on net imports, and second the net import trades over the interconnectors. The import/export curves describe the impact of imports/exports on area prices from each individual area. The curves are calculated in each area based on local energy bids/offers. FMC is designed to exist together with forward energy markets and transmission capacity markets and could therefore support the provision of FTRs. The objective includes the maximization of inter-regional transmission capacity. Likewise efficient trading between regional markets via power exchanges maximizes interregional market efficiency. However the DMC approach still has a number of outstanding issues, such as the development of the simplified transmission model and its consequences, the development of the coordinating algorithms and the definition of the performance measure. The network is modeled by a load flow model since it assumes that power transfer distribution factors are generated at regular point in time. All modeled electrical flow paths are taken into account not only contract paths. Anyhow the topology of the network will probably be simplified by modeling country-to-country flows rather than the complete set of interconnectors. Mathematical algorithms are needed to solve the simultaneous optimization of energy and net imports. These must be iterated by first calculating energy market clearing prices and next the amount of net imports between regions which again affect the energy market clearing prices. The number of iterations is ended when a certain convergence criterion is met.

EuroPex (2003) also discusses how FTRs and Nordic Contracts for Differences can be used when the decentralized market-coupling concept is used. The main precondition is the presence of a robust day-ahead reference price. Likewise Newbery and Neuhoff (2003) emphasize that FTRs are needed when energy and transmission markets are integrated which is likely to occur in Europe in the future.

5.2. The Italian transmission rights

Financial transmission right-like contracts were issued this year for the first time in Italy, on the difference between zonal prices within Italy and across the borders.[10]

The rights related to the internal zonal prices (CCCs) provide hedges on the difference between a zonal price and the national uniform purchase price (PUN), which is the price buyers on the day-ahead market pay. The uniform purchase price is a weighted average of the zonal prices paid to sellers. This feature makes the CCCs different from the Nordic CfDs.

The CCCs were auctioned off by the Italian ISO (Gestore della Rete di Trasmissione Nazionale-GRTN) and they are available for different time periods. The experience so far is quite limited, as we do not yet have a full year of operation.

Similar instruments (CCCIs) were issued on price differences across the borders, in conjunction with the introduction of implicit auction for the management of cross-border congestion (pursuant to EU Regulation number 1228/2003). CCCIs were allocated pro-rata (as it was the case with interconnection capacity until last year).

The transmission rights in Italy provide the holder a firm right to the price-difference payment. Therefore, the ISO is exposed to the financial risk of the underlying physical capacity being unavailable. However, the number of FTRs issued was determined through a conservative assessment of available physical transmission capacity. Therefore, the financial risk for the ISO is limited.

5.3. Contracts for Differences in the Nord Pool market

The Nordic market (i.e., Nord Pool) has introduced Contracts for Differences (CfDs)[11] in 2000. These financial instruments make it possible for the market players to hedge against the difference between

[10] This section is based on personal communication with Alberto Pototschnig at the Italian ISO (GRTN).

the area (zonal) price and the system price (the unconstrained price) in a future time period (Nord Pool, 2002). The area prices that are traded are: Oslo (NO1), Stockholm (SE), Helsinki (FI), Århus (DK1), and Copenhagen (DK2). Nord Pool has also introduced CfDs with reference to the German EEX price in June 13, 2005. The time duration of the Nordic CfDs are seasons (Winter 1, Summer and Winter 2) which will gradually replaced with monthly and quarterly contracts. Currently these contracts co-exist at Nord Pool for during the replacement period. Additionally there are annual contracts

The forward and futures contracts traded at Nord Pool are with reference to the system price. Producers are paid the area price for generation in their area. Consumers purchase load at their respective area price. Often, producers and consumers in different areas encounter situations of transmission congestion when the area prices differ from the system price. They may also be exposed to significant financial risks associated with congestion fees for bilateral transactions in the Nordic countries that are calculated based on the difference between the area prices times the transferred volume. Usually producers pay the fee, but parties can also make other arrangements.

The payment from the Nordic CfD is:

$$\text{CfD} = Q_i\,(AP_i - SP) \qquad (2)$$

in which AP_i refers to the area price in area i, SP is the system price, and Q_i is the contracted volume. Payments are calculated as the average of the difference between the daily area price and the system price during the delivery period (a season or a year) times the contracted volume. From Equation (2) we see that each time the area price is higher than the system price the holder receives a payment equal to the price differential times the contracted volume. Otherwise the holder must pay the difference.

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[11] Here, the term Contract for Differences is different from the corresponding term used in the British market. In the Nordic region, CfDs are used to hedge against the difference between the two uncertain prices (area price and System Price), not as in the British market, where they hedge the difference between the spot price and a pre-defined reference price or price profile. The Nordic CfD is a locational swap, while the British CfD is settled based on the difference between the spot price and the reference price. When referring to CfD in the Nordic market this paper uses Nordic CfD.

The market price of a Nordic CfD can be positive, negative or zero (Kristiansen, 2004). CfDs trade at positive prices if the market expects that the area price will be higher than the system price (a net import situation). CfDs trade at negative prices if the market expects an area price below the system price (a net export situation).

A perfect hedge using forward or futures contracts is possible only when the area price and the system price are equal. If forward or futures contracts are used for hedging, this implies a basis risk equal to the area price minus the system price. To create a perfect hedge against the price differential:

1. Hedge the specified volume by using forward contracts.
2. Hedge against the price differential – for the same period and volume – by using CfDs.
3. Accomplish physical procurement by trading in the Elspeth area of the holder of the contract.

Norway has adopted an area (zonal) price model to manage congestion in the day-ahead market. A charge equal to the difference between the system price and low area price times the transferred volume (capacity charge) is imposed in the low price area, and a charge equal to the difference between the high area price and the system price times the transferred volume is imposed in the high price area. Thus, withdrawals are charged in the high price area and compensated in the low price area. The opposite is true for injections. However, it is impossible to hedge against price differences within Norway, because there is only one contract with reference to the area Norway 1 (Oslo).

Shorter-term products than months and products for hedging directly against area price differentials are not available at the exchange. Kristiansen (2004) studied the prices of Contracts for Differences in the Nordic market and found that most of the contracts do not reflect the congestion rent. But there are also contracts that underestimate the congestion rent, resulting in a positive payoff to the holders. The Nordic CfDs are traded as forward contracts and do not have any connection to the congestion rent that the transmission system operator collects. The pricing of CfDs could be because the CfD market has only been in operation since November 2000 and therefore is immature. The majority of the results are in line with the pricing of futures at Nord Pool (Botterud et al., 2002).

6. Conclusions

This paper has presented an overview of the properties of financial transmission rights. New research by Leisure and Haskins (2005) show that the revenue adequacy test used in issuing FTRs may not hold true in AC power networks. This could potentially cause credit default problems for RTOs or ISOs and have implications for policies used for congestion revenue shortfalls.

Furthermore we described the latest experiences with FTR markets in the US. Baldick (2005) observes that no ISO provides a market for the contracting of both transmission and energy simultaneously. He therefore proposes to introduce a new contract called "contract for differences of differences" (CFDD). The CFDD does not require the RTO to be the issuer and devolves the risk to the transmission owner. In addition to being a hedging instrument, the contract supports new transmission projects or upgrading.

There is no practical experience in Europe with pure FTRs as defined in the US. Furthermore no countries in Europe use full locational pricing. The usual practice is zonal pricing or single area pricing. ETSO discusses FTRs in its taskforce group Network Access and Congestion Management Group. Likewise ETSO and EuroPex discuss the introduction of the concept flow based market coupling in the continental European electricity market. The concept is designed to exist together with forward energy markets and transmission capacity markets and could therefore support the provision of FTRs.

Italy has issued financialntransmission right-like contracts this year. The contracts are defined as the difference between zonal prices within Italy and across the borders. The transmission rights provide the holder a firm right to the price-difference payment. Therefore, the ISO is exposed to the financial risk of the underlying physical capacity being unavailable. However, the number of FTRs issued was determined through a conservative assessment of available physical transmission capacity. Therefore, the financial risk for the ISO is limited.

In the Nordic region, Contracts for Differences (CfDs) that are defined as the difference between the area prices and the system price have been in use since 2000 and new variants of the contracts have been introduced such as monthly and quarterly CfDs. Additionally a new CfD has been defined as the difference between the German EEX price and the Nordic system price. Hence this may stimulate to increased cross-border trades between the Nordic region and continental Europe.

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