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MARKETS FOR FINANCIAL TRANSMISSION RIGHTS

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ABSTRACT

This paper surveys the markets for financial transmission rights (FTRs) around the world. FTRs are used to hedge the costs associated with transmission congestion. Currently these rights are in use in PJM, New York and New England. A variant of financial transmission rights, which has both a physical and a financial aspect, was introduced in California in 2000. Similarly, flowgates were introduced in Texas in 2002. FTRs are also planned for introduction in New Zealand. The features of the FTRs and the design of the different FTR markets are described. The paper focuses on how FTRs can be acquired, their advantages and disadvantages, and their market performance.

Keywords: Financial Transmission Rights; Auctions; Hedging; Property Rights.

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INTRODUCTION

According to Hogan (2003) transmission policy stands at the center of electricity market design. The basic principles are open access and non-discrimination. Financial transmission rights (FTRs) facilitate competitive open transmission access. The proposed standard market design in the US will reduce seams between regions and markets. Certain critical market activities require standardization in order to support efficient operation with open access and non-discrimination. The design includes an independent transmission provider, which administers a single tariff and operates the transmission system to support essential services. There should be a coordinated spot market for energy and ancillary services, which employs bid-based security constrained economic dispatch with locational marginal cost pricing. The design includes bilateral contracts with a transmission usage charge for each transaction based on the difference in the locational prices at the points of injection and withdrawal.

In these electricity markets, generators receive the locational price at the point where they inject power into the market and loads pay the locational price at the point where they have withdrawn power from the market. When the locational price differs between the generator and the load, the load or generator may be subject to congestion fees. FTRs as described by Hogan (1992) entitle the holders of FTRs to receive the value of congestion as established by the locational price difference. Thus a holder of an FTR between a generator located at point A serving load at point B would be indifferent to any difference in the locational prices between the generator and load locations. The FTR would effectively reimburse the holder the same amount it pays in congestion fees. In the case of an FTR option the payoff would be non-negative. FTRs are assumed to redistribute congestion fees (or the congestion costs of market players), which can be considerable in the US power markets as illustrated in Figure 0-1. 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 Zealand and New England financial transmission rights. In Texas the flowgates are named transmission congestion rights (TCRs).

FTRs have been used in the PJM Interconnection since April 1, 1998, in New York since September 1, 1999, in California since February 1, 2000, and in New England since March 1, 2003. TCRs were introduced in Texas in February 15, 2002.

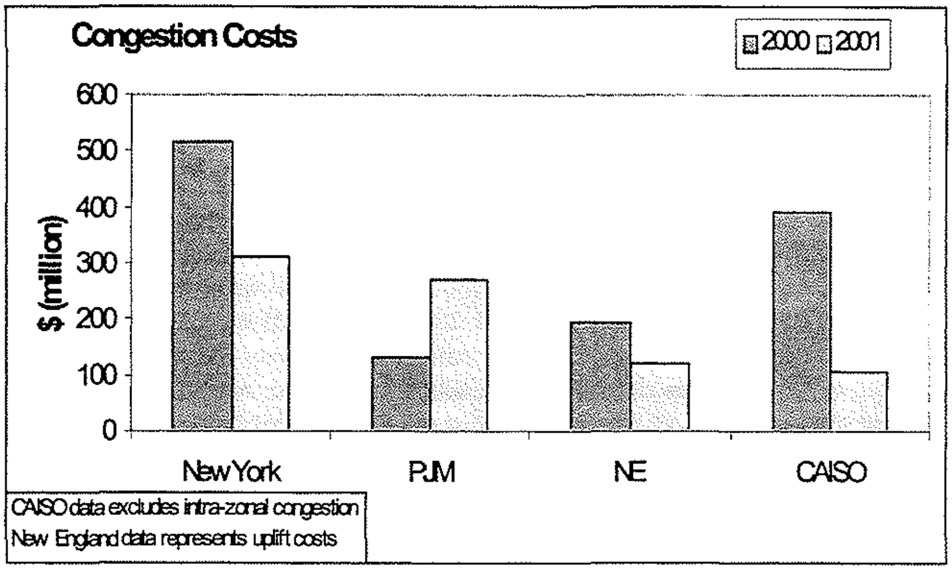

Figure 1-1. Congestion costs in the US power markets (Singh, 003).

PJM has introduced FTR obligations and options, while New York and New England have introduced FTR obligations, and are now evaluating FTR options.

Various jurisdictions have chosen different FTR designs. PJM, New York, New England and Texas have chosen purely financial contracts and TransPower New Zealand plan to do the same. California has introduced contracts that have both a physical and a financial element and that have similarities to flowgate rights (FGRs) and is currently evaluating congestion revenue rights, which are similar to firm transmission rights.

In this paper we firstly discuss the properties of financial transmission rights. Next, we describe market performance criteria. Then, we survey the FTR markets in PJM, New York, California, New England, New Zealand and Texas. The emphasis is on the PJM and New York markets, since they are the most mature markets. Finally, we make some concluding remarks and compare the different markets.

1. FINANCIAL TRANSMISSION RIGHTS PROPERTIES

Stochastic locational prices resulting in uncertain congestion charges create a demand by risk-averse market players for locational price hedging instruments. One such instrument is financial transmission rights (FTRs).

The congestion rents that the independent system operator (ISO) collects are redistributed to the market players through FTRs (Hogan, 1992). Financial transmission rights define property rights and provide market players with the financial benefits associated with transmission capacity and facilitate efficient use of scarce resources. Property rights are also a mechanism to reward transmission investments. The rights will give investors a tradable contract in return. The ability to hedge transmission price is an important feature in facilitating an efficient electricity market. Efficient pricing of FTRs through liquid trading provides economic signals for location of generation, load and transmission investments.

FTRs offer instruments for converting historical entitlements to firm transmission capacity into tradable contracts that keep the owners just as well-off as economically while enabling them to cash out when others can make more efficient use of the transmission capacity covered by these contracts. An attractive public policy issue is that the FTRs offer a convenient path to competitive open transmission access. This is critical in establishing a competitive electricity market.

1.1 Financial transmission rights

Because electricity flows according to Kirchoff's laws and is difficult to trace, 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.

An FTR gives the holder its share of congestion rents that the ISO receives during transmission congestion. The amount of issued FTRs is decided ex ante and allocated by the ISO 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 ISO. The surplus is redistributed to FTR holders and transmission service customers. On the contrary, if payments to FTR holders exceed the congestion rent, the ISO 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 ISO and depends on the market structure. FTRs entitle (or obligate) the holder to the difference in locational prices times the contractual volume. The mathematical formulation for the payoff is:

$$\mathrm{FTR} = Q_{ij}(P_j - P_i) \qquad (1)$$

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 quantity specified for the path from i to j. If the contractual volume matches the actual traded volume between two locations, an FTR is a perfect hedge against volatile locational prices.

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"[1] 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

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[1] 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).

a financial approach has been proposed in the literature (Hogan, 2002b). Baldick (2003) provides a critique of the flowgate implementation. He analyzes various economic and engineering aspects of the flowgate implementation in Texas. He finds that the implementation substantively violates the assumptions underlying the commercial transmission model.
For further information on financial transmission rights and other transmission congestion derivatives in the context of risk management, see Kristiansen (2004).

1.2 Allocation and pricing of financial transmission rights

FTRs can be allocated in different ways (Lyons et al., 2002). First, they can be given to those who invest in transmission lines. 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. 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 allocation of point-to-point obligation FTRs usually takes place in 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.

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) 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 mispriced. 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)

1.3 Revenue adequacy

A central issue in the provision of FTRs by an ISO is revenue adequacy. To maintain the credit standing of the ISO who is the counter party, the set of FTRs must satisfy the simultaneous feasibility conditions that are governed by the transmission 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. 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. 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).

The FTR market is operated in parallel with the spot market, and to ensure revenue adequacy the net demands from the FTRs must satisfy the power system constraints including transmission constraints. 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. Revenue adequacy is the financial counterpart of available transmission capacity (Hogan, 2002b). The feasibility test is included in the auction formulation, and pricing and trading of FTRs is done through a centralized period auction. Every FTR has an implied power flow, and the simultaneous interaction among the FTRs through the auction makes the FTR prices and the congestion fees hedged by these FTRs interrelated.

Oren et al. (1995) and Oren and Deng (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). Deng and Oren (2003) propose that the revenue adequacy requirement should be relaxed to a seasonal or annual accounting, or a value at risk approach.

1.4 Critique of the financial transmission rights model

Joskow and Tirole (2002 and 2003) provide an extensive critique of the short-run FTR model and its ability to create proper incentives for transmission investment. They argue that the FTR model is based on strong assumptions of perfect competition that allows efficiency. The assumptions include:

- no increasing returns to scale
- no sunk costs
- locational prices that fully reflect consumers' willingness to pay
- network externalities internalized by locational prices
- no uncertainty in congestion rents
- no market power so that markets are always cleared by prices
- complete futures markets
- ISO with no inter-temporal preferences regarding effective transmission capacity

The FTR model then allows investment in transmission to compete with investments in generation and provides a solution to the natural monopoly regulatory problem (Joskow and Tirole, 2002). However, if some of the above assumptions are not valid, the FTR model no longer creates proper incentives to prevent transmission congestion. In particular Léautier (2000) demonstrated this under a pay-as-bid pool rule where generators holding FTRs have incentives to reduce transmission capacity to enhance local market power. Similar results are found for physical transmission rights (Bushnell, 1999; Joskow and Tirole, 2000).

Joskow and Tirole (2003) have the following criticisms regarding the short-run FTR model:

- Market power raises prices in constrained area so that prices do not reflect marginal costs. Generators in a constrained region tend to withhold output to raise their price. The higher market-clearing prices therefore overestimate the benefits from the financial transmission rights.

- Existing and incremental transmission capacities are not well defined and are stochastic.
- Separation of transmission ownership and system operation creates a moral-hazard problem of type "in teams."
- The initially feasible set of FTRs may depend on uncertain exogenous variables.

Perez-Arriaga et al. (1995) point out that revenues from locational pricing only cover 25% of total costs. It is therefore necessary to combine FTRs with a fixed-price structure to recover fixed costs.

According to Hogan (2003) contingencies outside the control of the ISO could lead to revenue inadequacy, but such cases are rare and non-representative. Most contingencies are anticipated by running an N-1 security-constrained dispatch where the outage of a line or a generator is taken into account. Then the power flows after an outage would still be feasible in the dispatch.

1.5 Financial transmission rights and market power

Among researchers (Joskow and Tirole, 2000; Léautier, 2001; Gilbert, Neuhoff, and Newbury, 2002) there is consensus about the need to mitigate market power for any FTR auction to be efficient. Joskow and Tirole (2000) study a radial line network under different market structures for both generation and FTRs. They demonstrate that FTR market power by a producer in the importing region (or a consumer in the exporting region) aggravates their monopoly (monopsony) power, because dominance in the FTR market creates an incentive to curtail generation (demand) to increase the value of the FTRs. This is also in line with the conclusion in the FTR literature: generators can more easily exert local market power when transmission congestion is present (Bushnell, 1999; Bushnell and Stoft, 1997; Joskow and Tirole, 2000; Oren, 1997; Joskow and Schmalensee, 1983; Chao and Peck, 1997; Gilbert, Neuhoff, and Newbery, 2002; Cardell, Hitt, and Hogan, 1997; Borenstein, Bushnell and Stoft, 1998; Wolfram, 1998; Bushnell and Wolak, 1999). The behavior of the generators in the FTR market should then be regulated.

Allocation of FTRs to a monopoly generator depends on the structure of the market (Joskow and Tirole, 2000). When the FTRs are allocated initially to a single owner that is neither a generator nor a load, the monopoly generator will want to acquire all FTRs. When all FTRs initially are distributed to market players without market power, the generator will buy no FTRs. When the FTRs are auctioned to the highest bidders, the generator will buy a random number of FTRs. Extending this analysis, Gilbert, Neuhoff, and Newbury (2002) analyze ways of preventing perverse incentives by identifying conditions where different FTR allocation mechanisms can mitigate generator market power during transmission congestion. In an arbitraged uniform price auction, generators will buy FTRs that mitigate their market power, while in a pay-as-bid auction FTRs might enhance their market power. Specifically, in the radial line case, market power might be mitigated by not allowing generators to hold FTRs related to their own energy delivery. In the three-node case, mitigation of market power implies defining FTRs according to the reference node with the price least influenced by the generation decision of the generator.

In practical implementations of the FTR model, market power mitigating rules are designed (Rosellon, 2003). Federal Energy Regulatory Commission (FERC) has included market power mitigation rules in the standard market design (FERC, 2002). FERC indicates that insufficient demand-side response and transmission constraints are the two main sources for market power. FERC differentiates between high prices because of scarcity and high prices resulting from exercising market power. Using a merit-order spot market mechanism FERC proposes to use a bid cap for generators with market power in a constrained region and a "safety net" for demand side response. Regulated generators are also subject to a resource adequacy requirement. Chandley and Hogan (2002) claim that this mechanism is inefficient because the use of penalties for under-contracting (with respect to the resource adequacy requirement) would not permit prices to clear energy and reserve markets. Moreover, long-term contracting should be voluntary, and based on financial hedging, not on capacity requirements.

1.6 Financial transmission rights and transmission investment

Most electricity markets are by nature volatile and therefore no restructured electricity market in the world has adopted a pure merchant approach (Joskow and Tirole, 2002). The PJM and New York ISOs utilize long-term FTRs, and Australia uses a mixture of regulated and merchant transmission investments (Littlechild, 2003). Argentina also uses the hybrid approach under a locational pricing scheme.

Joskow and Tirole (2003) have the following criticisms regarding the long-term FTR model:

- Lumpiness in transmission investments makes payments to investors less than the increase in social surplus.
- Transmission investments are dynamic, and there is no perfect coordination of interdependent investments in generation and transmission. Supply and demand are stochastic and therefore locational prices are stochastic.
- The assumption about equal access to investment opportunities is not good because upgrading of the incumbent's network can only be efficiently put through by the incumbent.
- Inserting a new transmission line might have a negative social welfare value as demonstrated by Bushnell and Stoft (1997).

Some of the criticisms of the FTR model have been responded to by Hogan (2002a and 2003). The negative externalities can be taken care of by letting the investor pay for them as pointed out by Hogan (2002a). Moreover, Hogan agrees that the FTR market is only efficient when there is no market power, and when transmission investments are non-lumpy (or almost non-lumpy). He therefore indicates that merchant transmission investments should be for small-scale projects and that large and lumpy projects need regulation. Regulation is also necessary to prevent market power abuse. He argues that it is important to establish a boundary to differentiate between these investments.

Hogan (2003) also assumes that agency problems and information asymmetries are part of an institutional structure of the electricity industry where the ISO is separated from transmission ownership and where market players are decentralized. However, he claims that the main issue on transmission investment is the decision of the boundary between merchant and regulated transmission expansion projects. He argues that asymmetric information should not necessarily affect such a boundary.

The main consensus in the FTR literature is the need for co-existence of central planning and merchant investment for the long-term FTR approach to work and create incentives for transmission expansion. Central planning is necessary because of economies of scale, free riding and incentives to congest the network. Joskow and Tirole (2002) argue that there must be a careful definition of the function of the ISO in planning, timing, and degree of participation in transmission expansion.

It is not clear if a central planned system could be combined with unplanned investments given their impact on the existing and future transmission system. The probabilities of all states of the world over the investment horizon must be considered. However, these probabilities are not of common knowledge and the actual probabilities chosen by the ISO could be subjective. Moreover, contingency markets are hard to implement in practice because they assume that the owners of the existing network are not neutral with respect to new investments. Hogan (2003) points out that contingencies in the short-run are taken into account by running security-constrained economic dispatch.

The main incentive for investing in transmission capacity is that the benefits from the transmission investment outweigh the benefits from congestion. A long-term FTR model would give efficient results under such a criterion. On the contrary, a transmission company that benefits more from congestion than expansion would have no incentives to expand the network.

Barmack et al. (2003) claim that FTRs alone will not induce efficient operation and investment as a part of the United States' standard market design. They argue that an optimal incentive mechanism should meet at least two criteria. First, it should encourage the transmission owner to equalize the marginal social benefit of reduced congestion costs and the marginal cost of reducing congestion (including the short and long-run). Second, it should not discriminate between capital and operational expenses as potential means of reducing congestion, but rather should encourage the transmission owner to pursue whichever approach is most cost-effective. They differentiate between congestion rents (the income to the ISO from congestion) and congestion costs (redispatch cost). Based on a comparison between congestion rent shortfalls (or surpluses) and congestion costs they argue that the transmission owner is given incorrect incentives for efficient investment and operation. One of the criticisms is that investments eliminating congestion result in worthless FTRs. However, FTRs may be given to investors as a hedge against future price differences, not as a financing source. It is also difficult to make a correct allocation of FTRs. There is some amount of arbitrariness in the process of creating and allocating FTRs through the feasibility test. The model grid may be an inaccurate representation, resulting in over- or under-funding of payments to FTR holders. In the case of under-funding the transmission owner must make up the deficit and it will therefore have a risk by providing FTRs. Likewise, given the problems with allocating FTRs accurately, it may result in inefficient investments because investors are not allocated FTRs corresponding to the new capacity created. Barmack et al. (2003) also claim that the allocation of FTRs to investors in small-scale projects such as capacitors, transformers, or breakers will be imprecise and may not correspond to the new capacity created.

Barmack et al. argue that if the transmission owners should bear the risk of congestion rent shortfalls (from payments to FTR holders), they should be compensated by for example up-front payments to create funds that could be used to finance shortfalls. Alternatively, FTRs could be partially funded and pay only the congestion rents collected. Still another alternative is that independent transmission providers[2] (that are incorporating the assets of many different transmission owners) could issue FTRs in sufficiently restricted volumes so that shortfalls would be unlikely. As an alternative to FTRs they propose to use performance-based regulation.[3]

2. MARKET PERFORMANCE CRITERIA

This paper looks at the performance of the PJM and New York markets. 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 ISO. The FTRs are assumed to redistribute the congestion charges collected by the ISO during constrained conditions. In issuing FTRs, an ISO would use a simultaneous feasibility test, which ensures that the total amount of FTR issued can be provided under expected network conditions. If the issued FTRs meet this test under the same network capacity, then the ISO will collect sufficient revenues to cover all FTR payments. 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. In the case of obligations, the test is easy to perform, but for options the computational demands are more substantial.

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[2] Independent transmission providers include regional transmission organizations and independent system operators.

[3] The basic structure of their proposal is that the transmission owner is allowed to collect a transmission fee based on the expected levels of demand, the revenue requirement of the grid, and redispatch costs.

To evaluate whether the FTRs offer simultaneous feasibility, the ISO utilizes a model grid to ensure that offered rights are met by the capacity of the dispatch grid under expected normal conditions. Consequently, pricing and trading of FTRs is done through a central periodic auction. 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).

The model grid under expected network conditions may be an inaccurate description of the grid offered for dispatch, resulting in discrepancies between the congestion charges and the payoff to the holders of FTRs. The ISO redistributes excess congestion charges to the FTR holders and transmission service customers. Conversely, when there are deficit congestion charges, the ISO may reduce payments proportionally to FTR holders or require transmission owners to make up the deficit.
We compare FTR prices with the underlying asset by studying several examples of FTRs over time and locations.

3. THE PJM MARKET

The PJM market uses hubs for commercial trading. The hubs are a cross-section of representative buses and their prices are less volatile than a single point because they are weighted averages of locational marginal prices (LMPs). The three main hubs are:

- Western hub (111 buses)
- Eastern hub (237 buses)
- Interface hub (3 buses)

The Western hub is the most actively traded location. The day-ahead market in PJM (predominately Western hub) is considered to be the most liquid market in the USA.

3.1 History

PJM introduced locational pricing on April 1, 1998, and at the same time offered some players fixed transmission rights to hedge against price variations. An auction-based market for FTR obligations was introduced May 1, 1999 and options were introduced in June 2003. From 1999-2002 there has been an annual increase in congestion charges on the PJM system. The overall increase can be attributed to different patterns of generation, imports and load and in particular the increased frequency of congestion at PJM's Western interface which affects a majority of PJM load.[4]

Congestion in PJM was 58 percent higher in 2002 than 2001. This increase in measured congestion was partly due to the result of adding PJM-West facilities to the market, thus permitting the more efficient redispatch of local generation and making explicit the price differentials that resulted.

The significant increases in congestion suggest the importance of implementing the FERC order to begin to identify areas where investments in transmission expansion could relieve congestion that may enhance generator market power and support competition.

3.2 Fixed transmission rights

As initially defined by PJM, this is a purely financial contract that entitles the owner the right to receive compensation (even with no intent to deliver energy) for any transmission congestion charges present in the day-ahead market. A fixed transmission right (FTR) can protect the physical players that have costs correlated with the congestion fee and hedge the basis risk. It is not possible for the players to hedge against price differences due to losses with the present FTRs. FTRs are also issued together with firm transmission service.

FTRs are available for any location for which PJM posts an LMP (bus, aggregate, hub, or zone). They may be designated from injection buses outside of PJM and withdrawal locations inside PJM, injection buses inside PJM and withdrawal locations outside PJM, or buses with injections and withdrawals within PJM. For each hour with constraints on the transmission lines, the owner receives a portion of the congestion charges that are charged by the PJM ISO. The amount received is equal to the difference between the sink (point of withdrawal) and source (point of injection) LMPs multiplied by the actual amount of power specified in the contract as shown in Equation (2).

[4] 75 percent of PJM load is affected.

$$\begin{aligned}&\text{Congestion charge} = \text{MWh} \bullet (\text{day-ahead sink LMP} - \text{day-ahead source LMP})\\&\text{Point-to-point FTR credit} = \text{MW} \bullet (\text{day-ahead sink LMP} - \text{day-ahead source LMP})\end{aligned} \tag{2}$$

An FTR obligation may give the owner revenues or expenses depending on the specified direction of the contract. It gives revenues when the direction is the same as the congestion (the price at the injection node is lower than at the withdrawal node) and expenses if it is in the opposite direction. In the case of an FTR option the payoff is positive if the direction is the same as the congestion and zero otherwise. If FTRs were a perfect hedge, FTR holders would receive a credit equal to the FTR capacity reservation multiplied by the LMP difference between the point of delivery and the point of receipt of the FTR, when constraints exist. This is termed the transmission credit target allocation (Equation (2)). FTRs are not necessarily a perfect hedge and in fact FTRs have hedged the percentages shown in Figure 3-1 in 2001 and 2002.

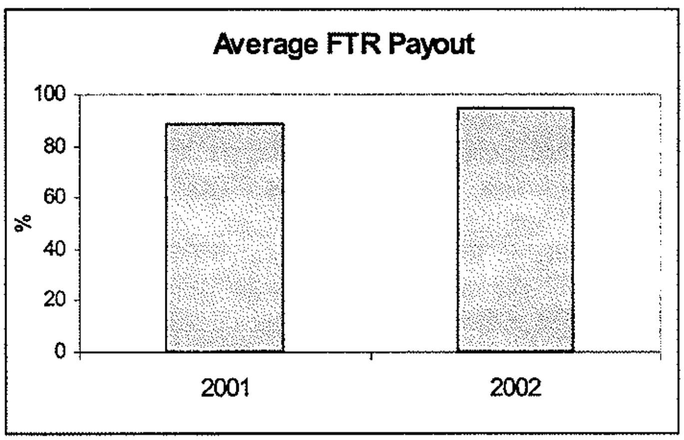

Figure 3-1. Average FTR payout for 2001 and 2002.

The congestion calculations steps are:

- Calculate congestion charges in the day-ahead and balancing market.
- Determine FTR target allocation based on day-ahead LMPs.
- Allocate congestion charges based on target allocations.
- Distribute excess revenues.

The FTRs do not hedge against real-time congestion charges, but teal-time market congestion charges can be hedged by submitting energy schedules into day-ahead market. Both the real-time and day-ahead congestion charges are used to fund the payments to FTR holders. If the FTR target allocation is not satisfied, the credits from the FTRs are reduced proportionally. Excess congestion charges are distributed by covering hourly FTR deficiencies within a month and from the previous month within a calendar year. The remaining excess revenues are distributed pro rata to network and firm transmission customers at year's end based on demand charge ratio shares.

The FTRs have to meet the simultaneous feasibility test (SFT) that was created to ensure that the transmission system supports the outstanding amount of FTRs, given a normal operation situation. If the FTRs can support a normal operation condition and congestion is present, the congestion revenues will be sufficient for the ISO to cover the payments to the owner of FTRs.

The FTRs can be allocated in periodic monthly auctions or in the secondary markets. The FTR secondary market is one in which holders and other entities that have acquired them sell FTRs on a bilateral basis. The contracts give coverage of congestion insurance for a month or longer. The buyers pay a premium for each right depending on the forecasted locational price differences. PJM evaluates proposals for new FTRs continuously. FTRs are also awarded to those who invest in transmission expansion, to the extent that the expansion allows additional FTRs that are simultaneously feasible with existing FTRs.

3.3 Acquisition and trading of FTRs

There are four ways to purchase FTRs:

- Network integration service (physical players).
- Firm point-to-point transmission service (physical players).
- Monthly FTR auctions (on- and off-peak).
- Secondary FTR market.

The time frame for the acquisition and settlement of FTRs in the PJM market is shown in Figure 3-2.

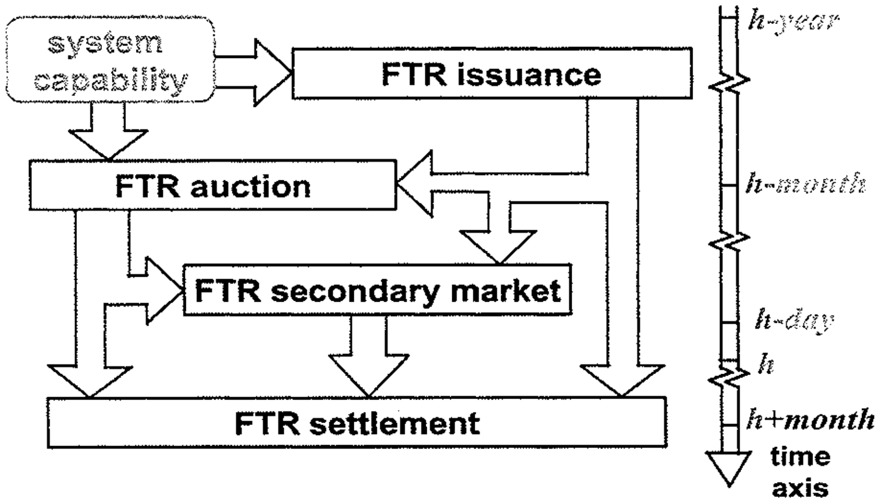

Figure 3-2. Time frame for the FTRs in PJM.

Transmission service customers who acquire network or firm point-to-point transmission service pay the embedded costs of the PJM transmission system. In return for paying these, the firm transmission service owners have the option to nominate for network resources[5] that they own or control to the zone(s) where their load was located in a quantity up to their coincident peak load within their zone.

Residual capacity is supplied in the market in two separate auctions: on-peak hours ending 0800 to 2300 and off-peak hours ending 2400 to 0700, including weekends and holidays. The supply of FTRs consists of the new issues plus any offers to sell by current FTR holders. Interested buyers may submit bids to buy FTRs. The market clearing-price is determined in a uniform-price auction and is different for FTRs defined between different pairs of sources and sinks. The secondary market and the auctions make it possible to trade existing FTRs independent of the initial allocation.

Annual FTR allocation processes provide FTRs only to network and firm point-to-point transmission customers. Initially PJM's secondary market allowed only the exchange of those specific FTRs. The initial process also provided that existing FTRs for network and firm point-to-

[5] Network resources are defined as generators that meet the PJM deliverability requirement, and may be nominated to be a capacity resource service. Capacity resource is net owned capacity from owned (or contracted) generating resources that are designated and committed by a load serving entity to serve its obligation under the reliability assurance agreement.

point service had priority in subsequent annual FTR allocations and that the FTRs were continued. The network FTRs were held by the providers (utilities) of retail service to network customers. A load serving entity (LSE) that wished to serve customers in a congested area had difficulty competing with an incumbent utility holding FTRs. The new entrant faced the risk of congestion while the incumbent did not.

To address this issue, effective as of June 1, 2001, PJM treated all requests for FTRs identically. The revised process allocated FTRs to network service customers based on annual peak load share rather than on historic priority. This resulted in opening access to FTRs to new LSEs that lacked historic FTRs.

However, the link between generation resources and ability to nominate FTRs remained. For example, two identical retail customers received different financial payments based on the generation resources owned by the LSEs that served them, as well as in the sequence in which those LSEs obtained the rights to claim such generation as capacity resource. The potential lack of any payments to those LSEs that acquired new load with an annual cycle remained as well.

Therefore in 2002 PJM approved a significant change to the method of allocating FTRs (PJM, 2003). The method was implemented for the planning year commencing June 1, 2003. The network FTR allocation process is discontinued and replaced with an annual FTR auction. This change provides a market evaluation of FTR value and permits all participants who value FTRs to bid a corresponding price to purchase them. Network customers is allocated FTR auction revenue rights (ARRs), which are the rights to collect the revenues from the FTR auction, based on the fact that network customers pay for the transmission system.

3.4 Network integration service FTRs

In PJM all LSEs must buy network integration service for all their loads. This method forces customers to pay the entrance fee to the grid. In exchange for paying these fees the LSEs receive some rights and obligations. They have an obligation to identify the production capacity that will deliver peak-load plus 20 percent. LSEs can choose to receive FTRs from the injection point (the generators), or the interconnection point with an external control area, to the withdrawal point for the aggregate load. FTRs are designated from unit-specific capacity resources, and cannot exceed the capacity contracted by the participant. The generators associated with the FTRs are referred to as designated network resources. The payoff from a network integration service FTR is:

$$\text{Network service FTR credit} = \text{MW} \bullet (\text{Day-ahead aggregate load LMP} - \text{Day-ahead generation bus LMP}) \quad (3)$$

The request process is annual, and the duration of the FTRs is from June 1 to May 31 of the following year. Modifications are allowed at any time. Network customers can choose combinations up to an amount equal to their peak load and can freely add or subtract FTRs as long as the amount of the outstanding FTR is feasible. Customers specify priority (between 1 and 4; 1 is highest) on their FTR requests. The maximum amount of FTRs for each priority is limited to a participant's 25 percent share of zonal peak load. If all FTR requests are not simultaneously feasible, the FTRs are then analyzed by priority level. Proration is required if all FTR requests within the same priority level are not simultaneously feasible. PJM can freely approve or not approve the proposed changes based on the SFT.

3.5 Firm point-to-point transmission service FTRs

Firm point-to-point transmission service means that the customer identifies two points and pays a fixed fee/tariff that basically equals the entrance fee for the network service. In exchange the customer may receive an FTR between the two points and request a volume up to the transmission service capacity level. Firm customers may receive FTRs for their transmission reservations and their bilateral contracts. The FTRs are for the same duration as associated firm point-to-point transmission service and can be requested annually, monthly, weekly or daily. The source may be a producer in PJM or an interconnection point with an external control area where power is injected. The load point may be one of the aggregated PJM nodes or the point of interconnection with the receiver's external control area.

The same approval process applies that is used in the network integration service. PJM approves all, some or none of the proposed FTRs based on SFT.

3.6 Auction revenue rights

ARRs are long-term rights and are allocated to firm transmission service consisting of network integration service and firm point-to-point transmission service. ARRs are acquired for one year and are allocated for the entire capability of the transmission system. ARR holders are entitled to the price difference between the sink and source LMPs established in the FTR auction times the numbers of ARRs they hold.

The maximum amount of ARRs is limited to participant's peak load responsibility within a zone. ARRs must be designated from unit-specific capacity resources to aggregate loads. The ARRs requested from capacity resource cannot exceed the capacity value contracted by the participant. Network customers specify priority (between 1-4) on their request (each priority level is limited to 25 percent of network service load share).

All ARR requests are tested for feasibility. If all FTR requests are not simultaneously feasible, the FTRs are then analyzed by priority level. All ARR requests within the same priority that are not simultaneous feasible are prorated. ARRs are allocated proportionally to the MW requested and inversely to their effect on constraint.[6]

The holder can convert the ARR into an FTR by "self-scheduling" the FTR into the annual auction on the exact same path as the ARR. It may reconfigure ARRs by bidding into the annual auction to acquire FTRs on an alternative path or for an alternative product. It may also retain allocated ARRs and receive associated allocation of revenues from the annual auction.

3.7 Monthly FTR auctions

After the initial allocation of the network- and point-to-point transmission service FTRs, an auction is held where any existing FTR or residual capacity can be traded to create new FTRs. PJM members and transmission service customers can submit bids to purchase residual FTRs and submit offers to sell existing contracts. The PJM ISO determines the winning offers and bids by maximizing the total surplus without violating SFT. Participants submit bids for capacity of service for a specified injection/withdrawal node pair, aggregates, hub or zone internal or external to PJM. PJM arranges monthly auctions (FTRs have one-month duration), which allow a reconfiguration of the total amount of rights.

The auction period opens 15 days before the FTRs are active. PJM calculates and informs about non-simultaneous possible FTRs for the PJM grid and the external connection points. The bids are checked and rejected bids are sent back to the owners for correction and new bidding. The bidding closes 10 days before the FTRs are active. Then the bids are

[6] ARR trades are allowed between affiliates only and must be completed prior to the opening of the annual auction. Network service peak load associated with the initial allocation of ARRs will also be transferred to the new holder for the purpose of reassignment.

evaluated according to SFT. The SFT decides a new number of "possible" FTRs by calculating a market price for each node, selecting the highest bid-based value combination of feasible FTR paths. The price of an FTR path is the difference between the injection and withdrawal point market clearing-prices.

3.8 Market performance

A major limitation to trading of FTRs is the lack of multiple requesters with the same injection and withdrawal nodes. The monthly auction market was introduced to increase the liquidity of FTRs. An increase in liquidity should occur when offering a mechanism for auctioning the residual FTR transmission capacity and increasing the supply of FTRs.

Buying bids, volume and revenue have increased, reflecting the willingness of buyers to pay higher prices for residual system capacity because of increased congestion. In the period May 1999-December 2002, 87 percent of the FTRs issued by the PJM ISO were of the network type and 1 percent were of the point-to-point type.

PJM's 2002 annual market report (PJM, 2003) indicated that the FTR market was competitive in 2002 and succeeded in its purpose of increasing FTR access. There was a steady increase in the capacity of cleared FTRs and cleared FTR auction prices.

Over the life of the FTR auction, the bid volume has exceeded the offer volume by nearly a 10:1 ratio, 45000 versus 5500 MW per month on average (PJM, 2003). The average bid and offer volumes were 52000 and 7000 MW per month in 2002. The cleared bid volume ranged between 3900 and 6400 MW per month during the 2000 to 2002 period, while the cleared offer volume ranged between 2200 and 5200 MW per month during the same period. Approximately two-thirds of the cleared bids were supplied from the cleared offers while one third drew on residual system capacity.

Prices in the FTR auction rose from \$356 to \$369 MW per month. Auction FTRs increased from an average of 3 percent of all FTRs in 1999 to 11 percent on average in 2000 and 2001, to 20 percent in 2002. Auction FTRs peaked in November 2002 when 11263 MW of on-peak FTRs cleared, representing 29 percent of all FTRs for the month. The auction revenue has doubled in each of the subsequent years since 2000, increasing to \$1.2 million per month in 2002.

An evaluation by the PJM Interconnections Market Monitoring Unit (MMU) to FERC (August 2000) after the first year concluded:

- FTR auctions succeeded in increasing the supply of FTRs.
- The main mechanism in the auction functioned well and trading increased.
- FTR auctions can affect the timing of the grid revisions.

The timing of the grid revisions is important because any player knowing in advance about planned revisions of the grid can use the information to take positions in the auction market. Grid companies will also have knowledge of revisions before it is public information. It is questionable if the grid companies take positions in the FTR market based on such non-public information. If the planned revisions increase congestion, the grid companies gain extra revenue from the contracts purchased before the revisions. One complaint was brought before the MMU, but no proof was found.

MMU proposed to PJM that all the grid owners must inform the market about the revisions at least two days prior to the auction closure. MMU also proposed a penalty for providing insufficient information about revisions. Grid owners must pay back any revenue from their revisions and they must give an updated plan of revisions one year ahead.

3.9 FTR payoffs and prices

The payoff from purchasing on-peak FTRs was calculated between 6 pairs of locations over the year 2002 in Table A-1 and Figure A-1 in the appendix. The payoff is defined as the difference between the average monthly point-to-point FTR credit target allocation and the monthly FTR clearing-price (in $/MWh). For these 6 FTRs, the payoff is positive for all except for one FTR. The standard deviation of the FTRs is higher than the average, implying highly uncertain market expectations about transmission congestion. During the year there are both negative and positive monthly payoffs. If the congestion charge target allocation exceeds the FTR credit target allocation parts of the FTR credit are reduced proportionally so both targets are met.

4. THE NEW YORK MARKET

New York introduced transmission congestion contracts (TCCs) September 1, 1999. The annual percentages of congestion hours for 2000 and 2001 are shown in Figure 4-1.

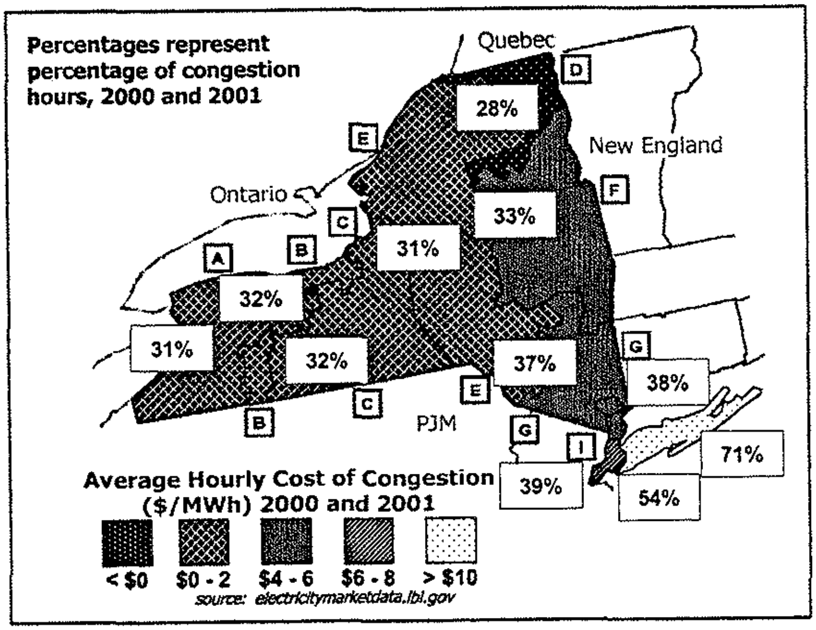

Figure 4-1 Congestion in the New York zones (Oren, 2003).

4.1 Transmission congestion contracts

Transmission congestion contracts (TCCs) are financial instruments for hedging against transmission congestion fees (New York ISO, 2003). The holder of the contract collects the congestion rent associated with transferring power from the source to the sink. The contracts are settled in the day-ahead market. In New York the locational prices are calculated based on an AC network (PJM uses a DC load flow) with marginal losses. However TCCs are only a hedge against congestion. The contracts are unidirectional and they become an obligation with reverse congestion.

The congestion charges apply uniformly whether the customers undertake a bilateral transaction or buy energy from the location-based marginal price (LBMP[7]) market. The congestion charges paid by the customers are collected in a TCC fund used to pay the primary holders of the TCCs and congestion paid to generators through LBMP. Over-collection of funds is allocated to the transmission owners to offset transmission system costs (TSC). Conversely, the transmission owners fund under-collection, and there is a true-up at the end of month.

[7]An LBMP is the same as a locational price or an LMP.

Transmission owners are contractually bound to honour existing transmission facility and wheeling agreements. Parties to existing agreements are said to hold grandfathered rights. They must continue to pay transmission rates under existing contracts and they do not pay congestion fees, but may be subject to curtailments. Grandfathered transmission rights have until the implementation of the End State Auction (expected 2004) to convert the rights into TCCs. The total transmission capacity is divided among grandfathered transmission rights, grandfathered TCCs, existing transmission capacity for native load (ETCNL), and residual transmission capacity (RTC). A portion of RTC was allocated to transmission owners as residual TCCs prior to the formation of the New York ISO (NYISO).

4.2 Acquisition and trading

TCCs can be purchased in MWs, and have durations of 6 months or 1 year. TCCs can be sold by direct sales, through a centralized TCC auction or via the secondary market. In the future. FTRs will also be awarded to those who invest in transmission expansion. Direct sales are allowed by FERC but not exercised by the transmission owners.

Available TCC transmission capacity is offered to qualified market participants through an auction process managed by the NYISO. The auction provides a means for market participants, through their bidding preferences, to determine which set of TCCs will be awarded. The auction is a uniform-price auction. It also allows primary holders to release the system transfer capability associated with their TCCs into the auction process. Upon completion of an auction, the ISO collects payment for all TCCs awarded for each round and the residual revenue is allocated to the transmission owners.

4.3 Auctions

The auctions have different stages:

- Phase 1: Two stages, multi-round auctions where stage 1 is a multi-round historical auction, and stage 2 is a single-round auction. It offers TCCs for specified durations in sub-auctions (historically) with 2 classes for each auction. The auction is conducted prior to each capability period (i.e. the minimum duration of the FTR).

- Phase 2: End State Auction for long-term TCCs. The annual auction will be implemented in 2004, and is a single-stage multi-round auction. Bids submitted by participants determine the durations of TCCs purchased. The ISO then determines the minimum and maximum durations for TCCs sold and the period (on peak, off-peak). Later, an auction may be conducted semi-annually to sell 6-month TCCs. The End State Auction will replace the Phase 1 auction.

TCCs purchased in stage 1 can be turned around and released at the seller's discretion in given stage 2 rounds. The participants can also bid on system transfer capability released in stage 2. The process starts 45 days before the auction period (i.e. the settlement period). The auction is conducted over 30 days consisting of two stages. Stage 1 usually has 4 rounds, and stage 2 has 1 round. This process enhances price discovery and avoids fire sales. Two weeks in advance the ISO posts the number of rounds to be conducted in each stage; the system transfer capability; power flow model; non-simultaneous closed interface limits; the accumulated LBMP congestion component per MW; and any special rules or conditions. One week in advance TCC holders and the NYISO enter their submissions. Six days in advance data is posted and then the auctioneer is ready to receive bids. The total system transfer capability is divided in equal portions among each round, for a total of 4 rounds.

Reconfiguration auctions are also held monthly in a single round. The duration of the TCCs sold is one month. The TCCs offered by primary holders capture short-term changes in transmission capacity. Primary holders may re-sell their TCCs in the secondary market. In 2002 there were spring, summer, autumn and winter (parts of 2003) auctions. The spring and autumn auctions consisted of 6-month TCCs that were auctioned in 4 rounds plus one reconfiguration round (i.e. stage 2), and annual TCCs that were auctioned in 2 rounds plus one reconfiguration round. The summer and winter auctions are monthly reconfiguration auctions.

Each TCC has a specific source and sink. The source and sink may be a generator bus, a New York control area zone, the NYISO reference bus, or an external proxy bus. This creates great diversity in the TCCs that can be formulated, and because of that, makes trading TCCs somewhat limited. With such diversity in TCCs there is less chance that one party (seller) will have the exact TCCs that another party (buyer) desires. The concept of "unbundling" addresses the diversity issue by unbundling a TCC into standard components, each of which is a TCC. Because there is less diversity in the standard components, many believe that standard component, or unbundled, TCCs will be easier to trade, thus increasing the liquidity of the TCC market. The standard components of a TCC are:

- TCC from source to the zone containing the source
- TCC from source zone to sink zone
- TCC from source zone to source

When a TCC is unbundled into standard components, the original TCC is replaced by up to three TCCs. The new TCCs retain the same capacity as the original. All TCCs sold in the spring 2000 initial TCC auction have been unbundled into their basic components effective as of September 1, 2000.

4.4 Market performance

In Figure 4-2 we show the auctioned volumes of TCCs. The auctioned volume increased almost 120 percent in 2000, around 50 percent from 2000 to 2001, and almost 9 percent from 2001 to 2002, reaching 140000 MW. The distribution of the TCC prices during 2002 is shown in Figure 4-3.

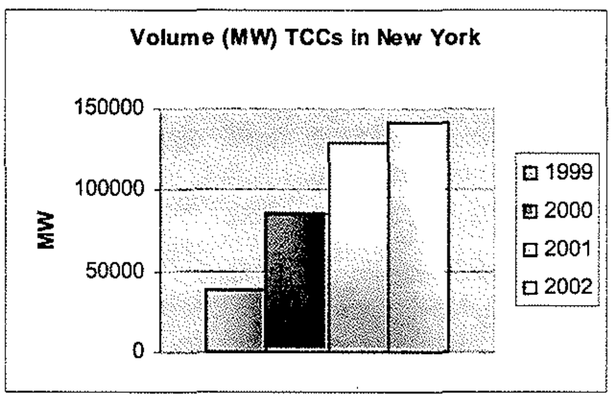

Figure 4-2 Annual volume in MWs of auctioned TCCs in New York.

In Table A-2 in the appendix we calculated the average auction prices and the average of the locational prices during the settlement period for some selected TCCs. There are discrepancies between the TCC price and the underlying locational prices, resulting in over- or under-collection of funds. When there is under-collection holders are honoured the residual payment.

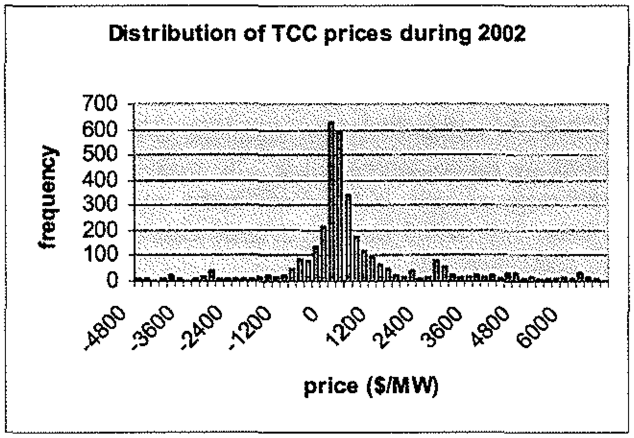

Figure 4-3. Price distribution of TCCs during 2002.

Siddiqui et al. (2003) analyze the TCC prices from the four initial auctions in 2000 and 2001. They find that the market performs relatively well. For example, buyers of TCCs predict congestion correctly most of the time. However, the TCC market does not appear efficient at hedging complex transactions involving larger exposures (greater than $1/MWh) or across multiple congestion interfaces. In this case TCC buyers pay prices including an excessive risk premium, which is far from being reasonable. Siddiqui et al. also find no evidence through cumulative analysis that the market players learn how to use the TCC more efficiently over time. These results might be symptomatic of a new market with rules unfamiliar to most market players. Likewise, arbitrage of price differences might not be possible because of illiquidity, risk aversion, and fear of regulatory intervention (Siddiqui et al., 2003).

5. THE CALIFORNIA MARKET

California introduced firm transmission rights[8] on February 1, 2000. California chose a model in which the California ISO (CAISO) auctions the contracts.

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[8] The financial part of firm transmission rights is similar to a flowgate right.

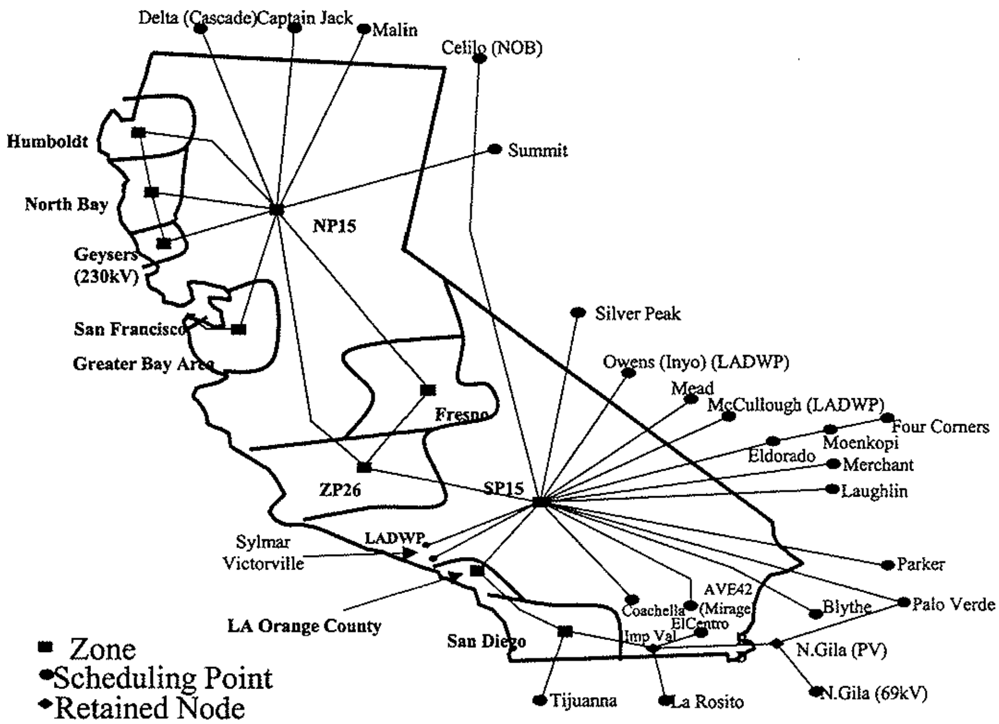

Figure 5-1 The California control area.

5.1 Firm transmission rights

California uses zonal pricing, meaning that nodes within an area with no or little congestion are aggregated into zones as shown in Figure 5-1. In the near future they will introduce locational marginal pricing and congestion revenue rights as a part of the market reform MD02 (CAISO, 2003). The FTR in California has one financial and one physical aspect. The contract gives the owner the right to transfer power and at the same time receive the potential share in the distribution of usage charge revenues collected by the ISO due to congestion between two predefined areas. Together these aspects amount to a lease.

The owner of the contract receives the contract quantity times the shadow price on available transmission capacity (ATC) on a specific flowgate associated with a transaction (in the day-ahead market) when the congestion is in same direction as specified in the contract. The FTRs give the users of the ISO-controlled grid a hedge (that might be perfect) against hourly variations in the costs due to transmission congestion. FTRs do not entitle owners to usage charges generated by counter-scheduling.

FTR holders have priority in the scheduling of energy across interfaces in the day-ahead market. Owners of FTRs who do not use the contract, lose the scheduling priority but keep the associated congestion payment. The amount of FTRs auctioned is equal to the ATC at the 99.5 percent level. This implies that the amount of FTRs outstanding approximately equals the actual generation and allows the ISO to allocate the outstanding capacity in the real-time power markets both hourly and daily.

If the transmission capacity on a line is reduced, the outstanding amount will not match the actual transmission capacity. All generation without FTRs will then be denied transmission. After that the generation with FTRs will be constrained proportionally with regard to priority (if all the FTRs have the same priority).

5.2 Acquisitions and trading

The FTRs are provided in an annual auction and have a duration of one year. The auction is conducted in mid-January and FTRs are settled from April to March of the following year. The owners of the FTRs can sell the contracts in the secondary and in the hour-ahead markets for a specified price by using adjustment bids. This gives players without FTRs the opportunity to buy transmission in the hour-ahead market from the owners or the ISO.

The surplus from the auction goes to the owners of the transmission lines (the transmission operators) to cover a part of the fixed cost of the underlying grid. The higher the surplus, the lower the connection fee for consumers.

5.3 Auctions

The auction is a multi-round and uniform-price auction. The initial period for the primary auction is one year. Within that limit, the ISO offers the option to create or eliminate new zones. FTRs with a duration of less than one year were too complex for the ISO to administer and reduced the incentives for creating liquid markets.

The amount of issued FTRs is calculated by determining the ATC for a branch group,[9] in a specific direction for each hour over the past

[9] A group of transmission branches that is treated as a single entity for purposes of running a congestion management market.

year. The hours are ranked from the highest to the lowest value, and the ATC is chosen at the 99.5 percent availability level. The value at 99.5 percent is the number of FTRs for sale.

5.4 Market performance

Table 1 shows the annual volume of auctioned firm transmission rights. The volume ranges from 9553-10475 MW and is relatively stable over time. Prices ranged from 165 $/MW to 17610 $/MW in 2002.

Year	**Volume (MW)**
1999	**9553**
2001	**10475**
2002	**10419**
2003	**9559**

Table 5-1. Volume of auctioned firm transmission rights in the California market (there was no auction in 2000).

5.5 Congestion revenue rights

The California ISO is currently evaluating congestion revenue rights (CRRs), which are similar to what FERC proposed in its standard market design (FERC, 2003). Transmission capacity will be awarded, allocated, and auctioned as CRRs in the following priority sequence: non-converted existing transmission contracts (ECTs), converted ECTs, ECTs under conversion, LSE nominations and CRR bids. Point-to-point CRRs are physical (scheduling rights) and financial rights in the day-ahead market. CRRs are defined between nodes or hubs and are forward contracts in which the holder is obligated to receive (or pay) the difference in LMP between the sink and source times the contractual volume. CRRs can also be offered as obligations or options to converted ECTs. Network service rights (NSRs) are forward contracts for fixed power transfers from multiple sources to multiple sinks. The sum of power injections at sources equals the sum of power withdrawal sinks. The sources and sinks can be network nodes or hubs. NSRs are financial obligations and solely financial (at this time). They will be allocated to LSEs as obligations and can be acquired through CRR auction and via the secondary market. CRRs can be unbundled as point-to-point CRRs for trading purposes.

6. THE NEW ENGLAND MARKET

New England introduced financial transmission rights (FTRs) in March 2003.

6.1 Financial transmission rights

The FTR is a financial instrument that entitles the holder to receive compensation for congestion fees that arise when the transmission grid is congested in the day-ahead market, and differences in day-ahead LMPs result from the dispatch of generators to relieve congestion (New England ISO, 2002). If a constraint exists in the network, the holders receive a credit target allocation based on the FTR MW quantity and the difference between the congestion components of the day-ahead sink and source LMPs. The holder receives credit regardless of who delivered the energy or the amount delivered across the path designated in the FTR. Similarly, an FTR is a financial obligation if the congestion flows in the opposite direction of the FTR.

If the monthly total of the positive FTR target allocations is less than the transmission congestion revenue, holders receive a congestion credit equal to their total positive FTR target allocations. If the monthly total of the positive FTR target allocations is more than the transmission congestion revenue, FTR holders receive shares of the monthly congestion revenues proportional to their total positive target allocations.

6.2 Acquisitions and trading

FTRs can be acquired or sold in auctions or in the secondary markets. Bilateral trading may be done independently or through ISO-administered bilateral trading. Reallocation also occurs in the auctions and secondary markets. The purchaser of an FTR in a bilateral transaction outside these markets receives only a contractual right against the seller of the FTR and has no rights or obligations in ISO settlement or in the energy market.

6.3 Auctions

The auctions are characterized by start and end dates, and are on-(ending hours 0800 to 2300 on weekdays) and off-peak (ending hours 2400 to 0700 on weekdays, weekends and holidays). The ISO conducts periodic auctions to allow eligible bidders to acquire FTRs. The auction is designated as a uniform-price auction. The SFT performed in the auction process ensures that there is sufficient system capability to support the FTRs sold and that congestion revenue is adequate to compensate the holders.

FTR auctions are introduced on a monthly basis, after which the ISO will conduct both longer-term and monthly auctions. The locations in the contracts are defined by LMPs at the source and sink and the contracts are awarded in tenths of a MW. The auction volume and revenue for the first three months are shown Figure 6-1

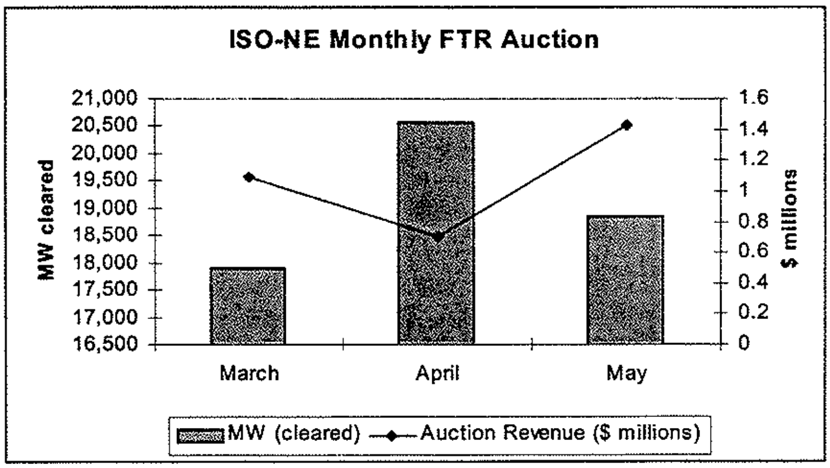

Figure 6-1. Auction volume and revenue for monthly FTR auction in New England.

Auction revenues are distributed to the FTR sellers and the ARR recipients. ARRs are awarded to entities (ARR recipients) paying for transmission upgrades which make it possible to award additional FTRs and allocate them to the entities responsible for paying congestion charges. A four-stage process determines each entity's ARRs based on its load share of all generation and its tie sources within the capability of the transmission system. Special recognition is given to certain contractual arrangements and the parties to those agreements.

7. THE NEW ZEALAND MARKET

A system with nodal pricing and a wholesale market was introduced in New Zealand in 1996. At the same time players were offered a price differential hedging product as a hedge against the increased risk. Transpower New Zealand (the system operator) agreed to provide this product for a limited period. The product gave restricted insurance against nodal price differences and had minimum and maximum prices to reduce the counterparty risk for Transpower. The product was withdrawn in 1998, because there was little interest among the players. It was more natural to let other players provide the product.

In New Zealand the congestion revenue is defined as the surplus from losses and congestion and is allocated among the users of the grid. In the present power system the system operator receives the congestion revenue. The system operator allocates the congestion revenue to the owners of the grid companies that are paying the sunk costs for transmission investments.

There is a debate in New Zealand about the introduction of FTRs. The industry says that Transpower has focused too narrowly on refining the concept, while ignoring broader issues and options. They also believe that there has been pressure to find a quick solution, rather than the appropriate solution. Opinions vary about who is entitled to the settlement surplus and has the right to develop an FTR and/or allocation regime.

7.1 Financial transmission rights

The proposed FTR will give the right to receive or the obligation to pay the difference in prices at the nodes (or hubs) for which the hedge is written for a defined amount of MWs and a defined period (Transpower, 2001 and 2003). An FTR will be an obligation and will have payoff:

$$\begin{aligned}\text{Payoff} = \text{MW} \bullet (&\text{Day-ahead sink nodal price} \\ &- \text{Day-ahead source nodal price})\end{aligned} \tag{4}$$

The nodal price contains both a congestion and loss component. Directional FTRs will consist of balanced FTRs (congestion) and spot FTRs (losses). Spot FTRs will represent injection at a node (or hub) to make up any shortfall in forecasted losses. Both spot and directional FTRs will be auctioned.

FTRs will be funded through transmission losses and transmission congestion rents. Transpower will offer the FTRs at a no profit/loss basis so all income from FTR auctions and residual rents will be returned via lower charges to the parties that pay the sunk costs of the grid. FTR payments are reduced proportionally when there are deficit congestion rents.

7.2 Acquisition and Trading

Today there are bilateral financial instruments to hedge against differences in nodal prices. Private players provide these products that have no effect on the physical market.

FTRs of 1-month duration will be auctioned monthly to all parties and can be traded freely in the secondary market. Later they may be offered for future months and longer durations. Together with the initial auction this will ensure that the FTRs are allocated to the players who value them most.

FTRs will be allocated for all new investments in the grid and will have duration equal to the lifetime of the investment. New investment FTRs may be offered into auction by the holder.

7.3 Auctions

The proposed auction-design is a pay-as-bid auction. After an introductory phase the FTR market will change to a 12-month forward market. FTRs could be sold for any volume (MW) and between every pair of nodes or hubs, given that the SFT is met. For future periods, reconfiguration auctions will be held monthly. Existing FTRs could be offered back into these auctions and additional FTRs purchased. It is expected that the LSEs, consumers, and producers will value FTRs higher than the other players, since their revenues are correlated with the price differentials. The auctions will be designed to ensure that the congestion rent and the FTR payments will balance. However, to the extent that the grid offered for dispatch will be different from the auction grid, there will be a risk that the congestion rents for that dispatch period will not cover FTR obligations. In such an event the FTR payments will be scaled down pro rata. Careful grid design will minimize the risks. The FTR auction income will be allocated to those who pay the sunk costs of the grid and is expected to be less variable than the congestion rents.

8. THE TEXAS MARKET – ERCOT

TCRs (flowgates) were introduced in Texas in February 15, 2002 and we briefly describe them here. The ERCOT market uses zonal pricing and flowgates. ERCOT employs an additional model to further manage local congestion. ERCOT implemented a direct-assigned allocation method for settlement of zonal congestion costs. The ERCOT market is a bilateral and ancillary service market and does not contain a spot market. All market players are required to submit balanced schedules through qualified scheduling entities.

Annually a (hopefully) relatively small number of "commercially significant" transmission constraints (CSCs) are identified. These CSCs are chosen to represent the limitations on moving power within ERCOT. For 2003, ERCOT had determined three CSCs as illustrated in Figure 8-1. TCRs are a financial right on a specified directional CSC for a particular date and hour that entitles the holder to receive remuneration from ERCOT for congestion fees on that CSC for that time and date. This means that the TCR holder will receive from ERCOT a payment which is equal to the directly assigned congestion fee of an equivalent amount of scheduled flow in both the balancing energy service market and the replacement reserve service market.

Another type of congestion right is the so-called pre-assigned congestion rights (PCRs), which are assigned to some entities who own or have a long-term (greater than five years) contractual commitment for annual capacity and energy from a specific remote generation unit, and that commitment was entered into prior to September 1, 1999. The market players who have PCRs can be exempted from a certain amount of congestion impact payment that will otherwise be charged as congestion fees. PCRs were tradable in 2003.

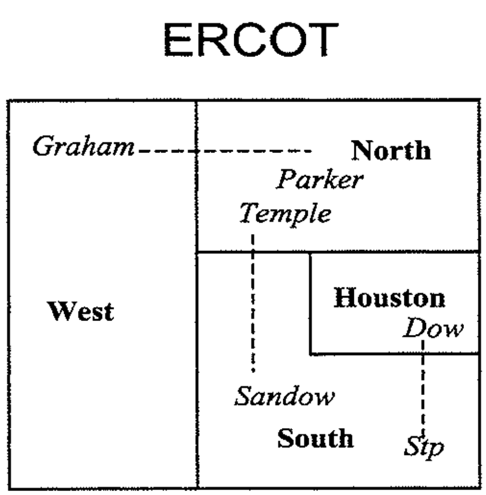

Figure 8-1:The commercially significant transmission constraints in 2003 Singh, 2003).

8.1 Transmission congestion rights

The payoff from a TCR is determined by taking the associated flowgate shadow price times the flowgate amount and totalling them for all lines that are affected by the transaction between the two buses (Equation (5)).

$$\begin{aligned} &\text{TCR} = \max(0, \eta HQ) \\ &\eta = \text{shadow price of the transmission constraints} \\ &H = \text{the matrix of shift factors} \\ &Q = \text{the contract volume} \end{aligned} \tag{5}$$

The TCR payoff only takes zero or positive values, so it is designed as an inter-zonal option. The clearing-price for each TCR equals the corresponding shadow price of the marginal TCR awarded on that CSC. The congestion rent is used to fund the payments to TCR holders and TCRs can be acquired in auctions. TCRs can be divided into smaller time segments and traded among market players in secondary markets. About 20 percent of the available rights are assigned as PCRs at reduced prices to municipally owned utilities and electric cooperatives that have grandfathered rights to the transmission system. Starting in 2003, PCR holders must pay 15% of the auction price of the TCR auctioned on the same CSC as the PCR.

8.2 Auctions

The ERCOT ISO conducted a simple, single round TCR auction for each CSC initially. The auction awarded the TCRs from the highest prices to the lowest prices until 100% TCR capacity is awarded. The lowest awarded price becomes the market-clearing price for the TCRs of the CSC. However, the auction was converted to a combinatorial auction of TCRs January 1, 2003. By the revision, the ERCOT ISO conducts a single-round, 24 simultaneous combinatorial auction for selling the TCRs available for each annual or monthly auction for all CSCs. There are annual and monthly uniform-price auctions. The revenues from the first two annual auctions are shown in Figure 8-2. ERCOT sells 60% of the total amount of TCRs less PCRs for any given CSC in its annual auctions. The remaining amount of TCRs is awarded to the participants in monthly auctions. According to ERCOT protocols, the revenues procured from these auctions will be credited to load entities in proportion to their load ratio share.

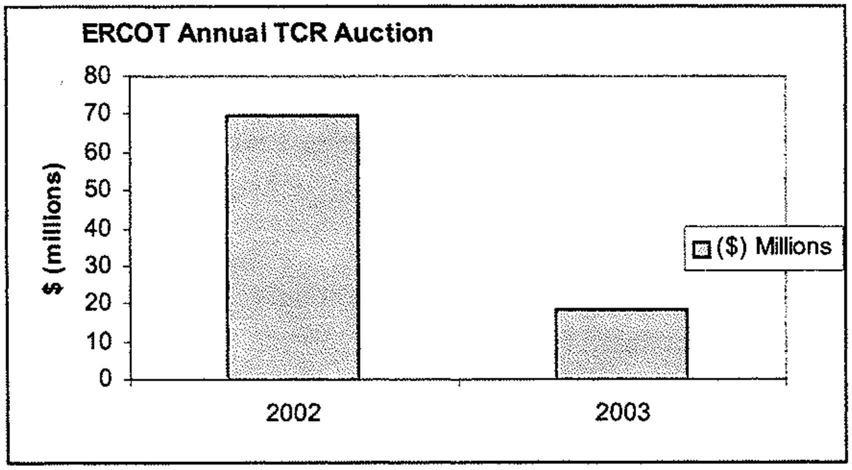

Figure 8-2. Revenues from the annual TCR auction (Singh, 2003).

8.3 Market performance

The number of annually auctioned TCRs[10] is shown in Table 8-1.

Year	Number
2002	10304
2003	8808

Table 8-1 Number of auctioned transmission congestion rights in the Texas market.

Evaluations made by ERCOT in 2002 and 2003 (ERCOT, 2004) concluded that:

- TCR auction revenues exceeded TCR credit payments in 2002
- TCR clearing-prices (costs) exceeded TCR credit payments in 2002
- TCRs were oversold in 2003, because the summer base case was based on a summer peak interval instead of a seasonal average, outages and discrepancies between the forecast model and real-time operations.

[10] The information materials from ERCOT only provided information about the number of TCRs.

CONCLUSIONS

This paper has presented an overview of markets for transmission rights around the world (Table 9-1, 9-2, and Table 9-3). The design and the rules of these markets are changing continuously. The information is complex and therefore this overview presents the author's understanding of the markets at the current time.

Table 9-1 shows the advantages and disadvantages of the FTR and flowgate markets. One major disadvantage is that all FTRs and flowgates are short-term hedges.

The numbers for trading volume indicate increased liquidity in the PJM and New York markets. However, the limited liquidity of FTRs in some regions inhibits trade. Efforts to increase liquidity should be made through trading hubs such as the PJM Western Hub. Unbundling may also contribute to increased liquidity. The system in PJM has limited liquidity and transparency for annual FTRs. Auction revenue rights will allow for better liquidity because they are not tied to the holding of network load or resources. New York conducts auctions with up to 4 rounds for the same FTR. There are also monthly reconfiguration auctions. This enhances price discovery and avoids fire sales.

Experience from the PJM market indicates that the process of allocating FTRs to utilities of retail service based on historic priority, inhibited competition because an entrant LSE had difficulties in acquiring FTRs. This problem was addressed by allocating FTRs to network customers based on annual peak load share rather than on historic priority. However, the link between generation resources and ability to nominate FTRs remained. From June 2003, the allocation of annual FTRs is according to a market valuation where players bid for FTRs (i.e. ARRs).

In New York grandfathered (historic) transmission rights are present. These are converted to TCCs in the End State Auction in year 2004. In this way TCCs offer mechanisms for converting historical entitlements to firm transmission capacity into tradable contracts.

The paper has also studied the FTR prices for some selected pairs of locations. Limited studies indicate that there are discrepancies between the FTR price and the value of the underlying asset. The reason is that the model grid used in the auctioning of FTRs is an inaccurate representation of the dispatch grid. This is not surprising, because unforeseen shocks during settlement periods are bound to occur. Siddiqui et al. (2003) analyze the TCC prices from the four initial auctions in

2000 and 2001. They find that the market performs relatively well. However, the TCC market does not appear efficient at hedging complex transactions involving larger exposures (greater than $1/MWh) or across multiple congestion interfaces. In this case TCC buyers pay prices including an excessive risk premium, which is far from being reasonable.

Today's information technology makes it relatively easy to collect and work through large amounts of data. It also makes it easier to design transmission rights and define the volumes. PJM designed a simultaneous feasibility test that ensures that FTRs are consistent with the possible schedules and the physical conditions in the grid.

PJM differs from other markets because its ISO assigns parts of the financial rights directly to the transmission service customers who pay the embedded cost of the transmission grid. The allocation is more restrictive because customers only can request FTRs up to their transmission service level.

<table>
<tr><th>Market</th><th>Advantages</th><th>Disadvantages</th></tr>
<tr><td>PJM</td><td>Western Hub liquid</td><td rowspan="5">No short-term hedges, lack of multiple requesters with the same injection and withdrawal nodes decreases liquidity, potential exercise of market power</td></tr>
<tr><td>New York</td><td>Multi-round and reconfiguration auctions enhance price discovery and avoids fire sales, unbundling</td></tr>
<tr><td>California</td><td>Multi-round auction, both physical and financial</td></tr>
<tr><td>New England</td><td></td></tr>
<tr><td>New Zealand</td><td>Hedge against losses</td></tr>
<tr><td>Texas-ERCOT</td><td>Facilitates liquidity</td><td>Non-perfect hedge, no short-term hedges, potential exercise of market power</td></tr>
</table>

Table 9-1. Advantages and Disadvantages of FTR markets.

Market	PJM	New York
Contract	Fixed transmission rights, financial, no hedge against losses, both obligations and options, auction revenue rights to transmission network customers	Transmission congestion contracts, obligations, no hedge against losses
Contract duration	1 month auction FTRs, annual network integration service FTRs, firm point-to-point transmission service FTRs have duration equal to the associated firm point-to-point service	6 months and 1, 2 and 5 year auction FTRs, monthly reconfiguration FTRs
Acquisition and trading	Network integration and firm point-to-point transmission service, auctions and secondary market	Auctions, secondary market
Initial allocation	Initially allocated to network integration service customers	Prior to the formation of the NYISO, there was an allocation of TCCs. In the first stage of this allocation, customers receiving service under existing transmission agreements were given the choice of converting their existing rights into either granfathered rights or grandfathered TCCs. After these rights had been allocated and accounted for, existing transmission capacity for native load was allocated to some transmission owners. Once all of these had been accounted for, residual TCCs were allocated to the transmission owners.
Auction design	Monthly (on- and off-peak), single-round, uniform-price auction	Seasonal (multi-round), monthly reconfiguration auctions, uniform-price auction
Liquidity, (volume traded 2002)	Bid: 624 GW Offer: 84 GW	Total: 140 GW
Congestion rents	Excess rents distributed to deficiencies in other periods, deficit rents reduce payments proportionally	Excess rents offset transmission system cost, deficit rents covered by the transmission owners
Distribution of auction revenues	FTR auction revenues are allocated among the regional transmission owners in proportion to their respective transmission revenue requirements	All revenues received by transmission owners from the sale of grandfathered TCCs and residual TCCs, as well as excess auction revenues, are credited against the transmission owner's cost of service to reduce the transmission service charge

Table 9-2. Comparison of FTR markets.

Market	California	New England	New Zealand	Texas-ERCOT
Contract	Firm transmission rights, financial with scheduling priority, option-like, no hedge against losses, congestion revenue right obligations and options will be implemented in the future	Financial transmission right obligations, no hedge against losses	Financial transmission right obligations, hedge against losses	Transmission congestion rights, financial, inter-zonal option,
Contract duration	1 year auction FTRs	Monthly auction FTRs	Monthly auction FTRs, investment FTRs have duration equal to the lifetime of the investment	Monthly and 1 year auction FTRs
Acquisition and trading	Auctions, secondary market, hour-ahead market	Auctions, secondary market, transmission upgrades, entities paying congestion charges	Auctions, secondary market, transmission expansion	Auctions, secondary market
Initial allocation	The initial allocation was through a primary auction of November 1999, in which FTRs equal to 100 percent of the operating limit at 99.5 percent availability were auctioned off. These FTRs were valid for a period of 14 months, from 1 February 2000 until 31 March 2001.	Monthly FTR auctions, longer-term auctions later	To be decided	Auctions
Auction design	Annual, multi-round and uniform-price auction	Monthly, single-round, uniform-price auction	Monthly, FTR for investments in the grid, pay-as-bid auction	Annual, monthly, single-round, a single-round, 24 simultaneous combinatorial auction
Liquidity, (volume traded 2002)	Total: 10.4 GW	Introduced March 2003, limited data available	To be implemented	10304 CTRs (number of CTRs)
Congestion rents	Excess rents partly cover the fixed costs of the grid, deficit rents reduce payments proportionally	Excess rents redistributed to FTR holders, deficit rents reduce payments proportionally	Excess rents redistributed to those who pay the sunk costs of the grid, deficit rents reduce payments proportionally	Any rent shortfall is uplifted to load and any surplus is credited against any other uplift to load
Distribution of auction revenues	The primary auction proceeds went to the participating transmission owners. Each participating transmission owner credited its FTR auction proceeds against its access charge	FTR auction revenues are distributed to sellers of FTRs and auction revenue rights recipients		Credited to load entities in proportion to their load ratio share.

Table 9-3. Comparison of FTR markets.

The contracts proposed for introduction in New Zealand include payments for losses. This means that an FTR gives the owner the right to the entire price difference between two nodes, both the one due to losses and the one due to congestion. In New York an AC network is used, which takes losses into account, but the FTR does not hedge against losses. In most of the literature the transmission rights only give the right to differences in price due to congestion. Harvey and Hogan (2002) give an overview about how to design FTRs for hedging against losses.

The introduction of FTRs/TCCs in the different systems in the USA must be viewed in relationship to the organization of the market. Often private players own the central grid, but a system operator operates it. The FTR is a means to reduce the possibilities for the grid owners or system operators to exercise market power.

In all markets the FTRs are supposed to redistribute the congestion charges to the users of the transmission services. This creates incentives for transmission providers to maintain and expand the transmission grid, thus reducing congestion.

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APPENDIX

PJM FTR prices

FTR	Average payoff	Standard deviation
BAYONNE 138 KV COGEN1 PVSC 138 KV T-1	-0.06	0.12
BRUNNERI 230 KV DIES WHEMPFIE 138 KV PRIN_1	0.21	0.71
COLLINS 115 KV LD1 NEWBERRY 115 KV 1 BANK	1.13	4.15
WHITPAIN WHITEMAR 230 KV DBU6	0.75	1.40
HOMERCIT 20 KV UNIT 2 HOMERCIT 23 KV DUM2	0.07	0.55
DEANS PSEG	0.14	0.52

Table A-1. Average payoff and standard deviation from selected FTRs in the PJM market in $/MWh during the year 2002.

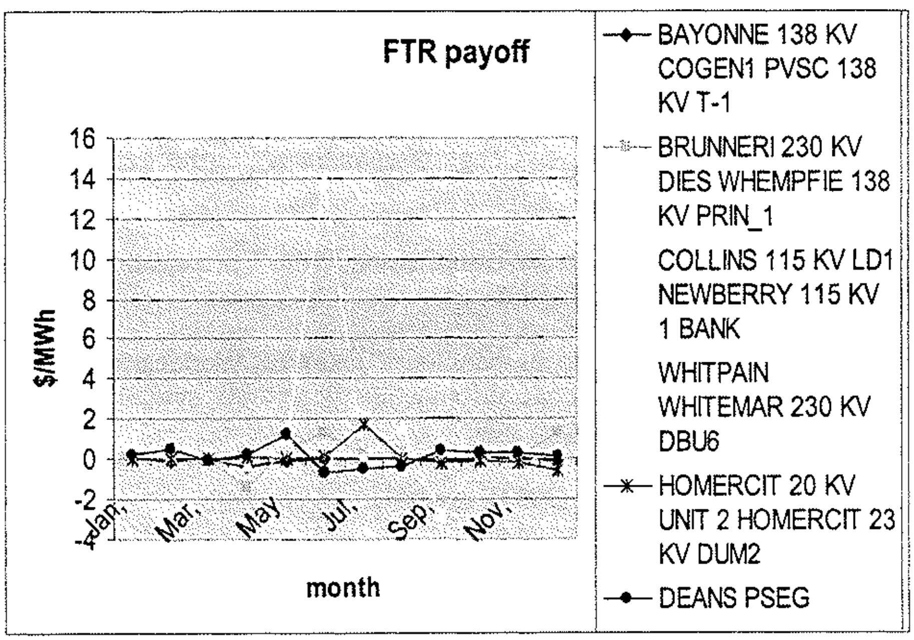
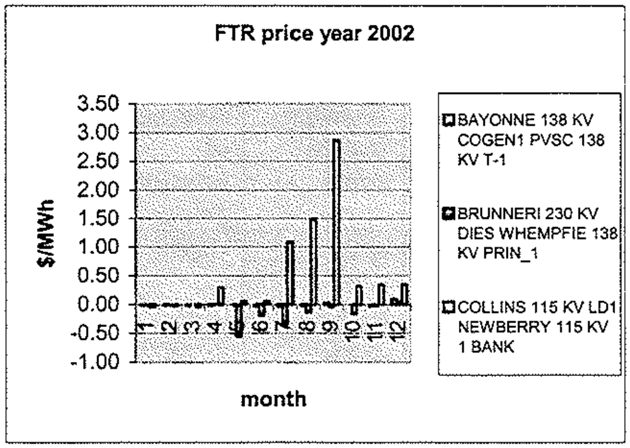


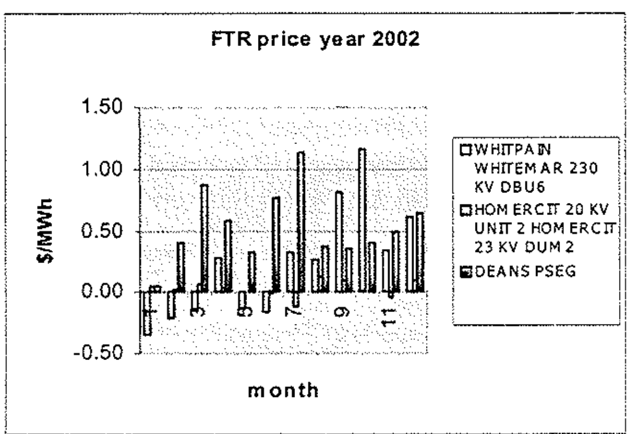
Figure A-1. Payoff from selected FTRs in the PJM market in $/MWh during the year 2002.

Figure A-2. Selected monthly FTR prices during 2002



The payoff is defined as the difference between the average monthly point-to-point FTR credit and the monthly FTR clearing-price (in $/MWh) and is illustrated in Table A-1 and Figure A-1. The prices are shown in Figure A-2 and Figure A-3. Table A-1 shows that the average payoff during a year is positive for all FTRs except BAYONNE 138 KV COGEN1 PVSC 138 KV T-1. The standard deviation is higher than the average, implying highly uncertain market expectations about transmission congestion. During the year there are both negative and positive payoffs. The FTR COLLINS 115 KV LD1 NEWBERRY 115 KV 1 BANK has the highest payoff (13.91 $/MWh) in July 2002. Conversely the lowest payoff (-2.80 $/MWh in September) is for the same FTR. This FTR has the highest standard deviation of all contracts.

Figure A-3. Selected monthly FTR prices during 2002.



New York TCC prices

	Average traded price	**Average of locational prices**	**Payoff**
Spring 2002 auctions round 4 MHK VL – CENTRL	-0.01	-1.53	-1.52
HUD VL – N.Y.C	4.84	-8.38	-13.22
HQ-NYISO_LMBP_REF	-0.48	-0.24	-0.71
HUD VL – N.Y.C Jan. reconfig.	2.12	-0.65	-2.77
Feb. reconfig.	1.75	-0.13	-1.88
Mar. reconfig.	1.08	-0.92	-2.00
Jun. reconfig.	6.00	-9.12	-15.12
DUNKIRK_3 NEG WEST_LANCAS, Jan. reconfig.	-0.12	0.34	0.46
Feb. reconfig.	-0.09	0.29	0.38
Mar. reconfig.	-0.06	0.41	0.47
RAVENSWOOD_G-HUDSON Jan. reconfig.	-0.08	0.28	0.36
Feb. reconfig.	-0.05	0.09	0.14
Mar. reconfig.	-0.04	0.01	0.05
PJM-HQ_GEN_CHAT_DC Jan. reconfig.	0.68	1.55	0.87
Feb. reconfig.	0.37	1.02	0.65
Jun. reconfig.	-0.50)	0.35	0.85
Oct. reconfig.	-0.44	0.69	0.25

$/MWh in the New York market.

Table A-2 shows the auction prices of selected TCCs and their associated spot prices in $/MWh in the New York market.