CHAPTER 3: Point to Point and Flow-based Financial Transmission Rights: Revenue Adequacy and Performance Incentives

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Abstract We provide an introduction to financial transmission rights in electricity markets with locational marginal pricing (LMP) explaining the mechanics and fundamental relationships between point to point Financial Transmission Rights (FTRs) and Flowgate Rights (FGRs). We then examine the issue of revenue adequacy in FTR/FGR markets and address two questions: a) How should revenue shortfalls in FTR markets be assigned to market participants? and b) How can active participation by transmission owners in FTR markets incentivize transmission performance through incremental and long term investment? In particular we focus on the possibility of short positions by transmission owners on financial Flowgate Rights (FGRs). Such positions would allow their holders to capture some of the FTR auction revenues in exchange for assuming liability for the corresponding FTR market revenue shortfall, which can be avoided through improvements in line ratings.

1. INTRODUCTION

The prevalent market mechanism for defining transmission rights in North American restructured electricity markets is through financial instruments that enable energy traders to hedge congestion risk. The underlying quantities for such instruments are either Locational Marginal Prices (LMP) or shadow prices on transmission flowgates which are determined as part of an Optimal Power Flow (OPF) calculation. There are three prevalent forms of financial transmission rights whose settlements are based on the above underlying quantities:

FTR Obligations – These are LMP SWAPS defined over specific time intervals and between specific nodes, whose holder is entitled to receive, or obligated to

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pay, the nodal price difference between designated locations per MW denomination

FTR Options – These are one sided LMP SWAPS defined over specific time intervals and between specific nodes, whose holder is entitled to receive the nodal price difference between designated locations per MW denomination if that difference is positive (but can walk away if it is negative.)

FGR – These are directional rights defined over specific time intervals and specific links, entitling their holder to the shadow price on the link's capacity constraint in the designated direction per MW denomination.

Alternative forms of entitlements to the transmission infrastructure which have been used in the past or are still used in parts of the world include contract path rights which are based on a fictional "commercial path" between designated locations, or physical capacity rights between designated locations or on specific network interfaces. One major shortcoming of such physical rights is that they require coordination between the dispatch and transmission rights ownership. Furthermore, when the rights definition is not consistent with the physical flows induced by specific point to point energy transactions (as is the case for contract path), then the available transmission capacity between points (ATC) varies depending on overall dispatch patterns, making it difficult to issue entitlements that extend over long time periods. By contrast, financial rights have the advantage of enabling complete decoupling between the actual dispatch and the settlement of congestion charges. The system operator can dispatch generation resources in the most efficient way with no regard to how transmission rights ownership, and impose congestion charges based on actual use of the network. The congestion revenues are then distributed to the rights holders so that a network user whose transmission rights holdings match its network use breaks even. Any discrepancies between use and financial rights holdings will result in financial shortfalls or surpluses but will not impact dispatch efficiency. Furthermore, insuring that the amounts of FTRs and FGRs issued conform with physical feasibility enables the issuance of long term rights with minimal financial risk to the underwriters.

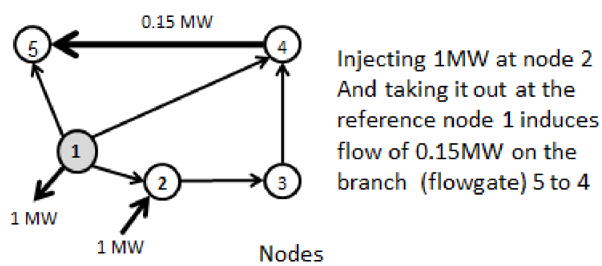
FTRs defining point to point financial transmission rights have been first introduced within a general framework of contract networks by Hogan (1992) and have been widely adopted in the US as an integral part of the nodal market designs implemented by the various independent system operators. Flow based transmission rights (financial or physical) have been first introduced in a seminal paper by Chao and Peck (1996). The potential use of FGRs, which are financial flow based rights, as substitutes or complements to FTRs has been discussed by Chao and

Peck (1996) Chao et al. (2000), Ruff (2001) O'Neill et. al. (2002) (and in numerous follow-up papers. However, FGRs, are rarely used in today's markets since energy traders prefer FTRs that are more suitable for hedging point to point congestion risk. Specifically, a bilateral energy transaction of X MW from node A to another node B in the network is exposed to congestion risk between the two location and is liable for a congestion charge that equals to the difference of LMPs between the two node. That charge is equivalent to the net cost resulting from selling the power at node A and buying it back at node B at the respective nodal prices. A trader can offset such a congestion charge by holding an FTR from node A to B for X MW which entitles him to the nodal price difference between node B and node A time X. Hence the FTR payoff exactly equals the congestion charge. Conceptually, however, FTRs and FGRs are equivalent due to a fundamental relationship between nodal price differences and flowgate shadow prices which is explained in the next section (see Chao et. al. (2000). To understand the relationship between FTRs, FGRs and how they relate to optimal dispatch and locational marginal pricing we begin with a brief tutorial explaining these basic concepts in the following section.

2. A PRIMER TO LMPS, FTRS AND FGRS

The objective of Optimal Power Flow (OPF) is to find the output levels for a set of generation resources that are distributed over a transmission network (and are already running and synchronized), so as to minimize total cost of serving specified loads (or maximize social welfare if loads are characterized by price sensitive loads), while accounting for losses and without violating transmission flow constraints. In general flows on transmission links are determined by Kirchhoff laws for Alternating Current (AC) and they must satisfy thermal and voltage limits. For the purpose of this exposition, however, we will ignore losses and assume a Direct Current (DC) approximation of Kirchhoff's laws in which case flows are only constrained by thermal limits specified for each transmission line.

Under such simplifications the flow pattern in a network can be characterized in terms of a matrix of Power Transfer Distribution Factors (PTDF) whose ij element specifies the incremental flow induced on each transmission link j by injecting one incremental MW at node i and withdrawing it at some designated reference node. The transmission links are specified as directional so negative flow indicate flow in the opposite direction. In the following, for clarity, we will denote the transmission links by pairs of indices representing the adjacent from/to nodes so that hk represents the directional link from node h to node k. The PTDF matrix can be easily computed through simulation or directly from the electrical properties (susceptances) of the transmission lines. As an illustrative example Figure 1 gives the PTDF matrix corresponding to the 5 node network shown, with node 1 as reference node. This example due to Fernando Alvarado (2000) portrays a stylized representation of the PJM system.



Branches \ Nodes	1	**2**	3	4	5
1to2	0.00	0.67	0.54	0.19	0.03
2to3	0.00	-0.33	0.54	0.19	0.03
3to4	0.00	-0.33	-0.46	0.19	0.03
4to5	0.00	**-0.15**	-0.29	-0.37	0.11
1to4	0.00	0.18	0.25	0.44	0.09
1to5	0.00	0.15	0.21	0.37	0.89

Figure 1: PTDF matrix for five node example

According to the PTDF matrix in Figure 1, $PTDF_{45,2} = -0.15$, indicating that injecting 1MW at node 2 and withdrawing it at the reference node 1 results in 0.15MW flow on the line connecting nodes 4 and 5 in the direction from 5 to 4 (opposite to the designated *45* direction). The PTDF matrix can be used to determine the impact of injections and withdrawals at any pair of nodes on any transmission line using superposition. For instance, the flow on the line 1 to 4 resulting from injecting 1MW at node 2 and withdrawing it at node 5 is given by $PTDF_{14,2} - PTDF_{14,5} = 0.18 - 0.09 = 0.09$. This calculation is invariant to the choice of reference node since, the PDTF matrix for any reference node *i* can be obtained from the given matrix by subtracting the column corresponding to the reference node in the given PTDF matrix from each of the columns.

As indicated above the underlying quantities for financial transmission rights are locational marginal prices (LMPs) or line shadow prices (SP). These quantities are meaningful in the context of optimal power flow or optimal dispatch. A well-known property of optimal dispatch is that if no transmission constraint is binding, then the marginal cost of serving one incremental unit of energy at any node is identical and there is at least one marginal generation unit that can be moved to produce such an incremental unit at that cost. A less obvious result is that if one transmission line is congested and the system is dispatched optimally, then supplying an incremental unit of energy at any node without violating the binding constraint can be achieved by adjusting the output of up to two generation units, so called, marginal generators which can be moved up or down. This principle can be generalized in the sense that when the OPF results in m binding constraints then supplying an incremental unit of energy at a specific node without violating the constraints may require change in output levels of up to m+1 marginal generators. Solving an OPF problem determines the output levels of all operating generators and identifies the marginal units which implicitly determines the LMPs and transmission line shadow prices. Following are intuitive definitions of these two concepts.

Locational Marginal Price (LMP): *The least cost of providing an incremental unit of energy at a node under optimal dispatch, without violating the binding transmission constraints***.**

Line Shadow Price (SP): *The maximum dispatch cost savings, under optimal dispatch that can be achieved due to an incremental unit increase in the lines' flow capacity constraint without violating any of the binding transmission constraints.*

Given the set of marginal generators corresponding to an OPF solution and the PTDF matrix we can calculate the LMPs and Shadow prices according to the above definitions. Clearly only lines operating at the limit have positive shadow prices and LMPs at nodes with generators that are free to move up or down will equal that generator's marginal cost. However, at nodes with no generation or with generators operating at their capacity limits (up or down), the LMP can be positive or negative. To illustrate the LMP calculation consider the example in Figure 1 and assume that the line connecting nodes 4 and 5 is operating at its limit in the 5 to 4 direction under optimal dispatch where the two marginal generation units are at node 1 with marginal cost of \$15/MWh and at node 4 with a marginal cost of \$30/MWh. To determine the LMP at node 2 we must calculate the incremental outputs Q_1, Q_4 of the marginal units at nodes 1 and 4 so as to deliver 1MWh to node 2 without increasing the flow on the congested line. From the PTDF matrix in Figure 1 we can determine that 1MW injected at node 1 and withdrawn at node

2 will increase flow on line 4 to 5 by 0.15MW. Likewise injecting 1MW at node 4 and withdrawing it at node 2 will increase flow on line 4 to 5 by -0.37+0.15=-0.22MW. Thus the quantities Q_1, Q_4 must satisfy the system of equations:

$$\begin{bmatrix} 0.15 & -0.22 \\ 1 & 1 \end{bmatrix}\begin{bmatrix} Q_1 \\ Q_4 \end{bmatrix} = \begin{bmatrix} 0 \\ 1 \end{bmatrix} \Rightarrow Q_1 = 0.59 \quad Q_4 = 0.41$$

Hence the cost of supplying a marginal 1MW at node 2 which is the LMP at node 2 is given by:

$$\mathrm{LMP_2{=}15 \cdot Q_1{+}30 \cdot Q_4{=}}15 \times 0.59 + 30 \times 0.41 = \ \$21.15\,/\,\mathrm{MWh}$$

A similar calculation can be performed to determine the shadow price on the line connecting nodes 4 and 5 in the congested direction 4 to 5. Now the objective is to perturb the outputs of the marginal units by incremental amounts Q_1, Q_4 so as to increase the flow on the congested line 5 to 4 while maintaining the energy balance. The resulting quantities can be determined by solving the system of equations:

$$\begin{bmatrix} 0.15 & -0.22 \\ 1 & 1 \end{bmatrix}\begin{bmatrix} Q_1 \\ Q_4 \end{bmatrix} = \begin{bmatrix} 1 \\ 0 \end{bmatrix} \Rightarrow Q_1 = 2.7 \quad Q_4 = -2.7$$

Which tell us that the increased capacity enables us to increase outpout from the cheap marginal unit at node 1 by 2.7MW while reducing the output of the expansive marginal unit at node 4 by the same amount. Thus, the incremental change in dispatch cost due to a unit increase in capacity of the congested line (flowgate) which is the flowgate shadow price is given by:

$$\mathrm{SP_{54}{=}15 \cdot Q_1\text{-}30 \cdot Q_4{=}(15\text{-}30)} \times 2.7 = \ \$40.5\,/\,\mathrm{MW/h}$$

It should be noted that shadow prices are direction specific and have non zero values only if the line flow is at capacity. So in the above example $\mathrm{SP}_{45} = 0$, since the line flow capacity constraint in the direction 4 to 5 is not binding.

Clearly there is a close relationship between LMPs and flowgate shadow prices both of which are calculated from the same data. In general it can be shown that for any pair of nodes *i,j* the following fundamental relationship holds.

$$LMP_j - LMP_i = \sum_{\text{all flowgates hk}} SP_{hk} \cdot (PTDF_{hk,j} - PTDF_{hk,i})$$

As explained earlier a 1MW point to point FTR obligation is a forward contract entitling (or obligating) its holder to receive or pay the stream of LMP differences between two specific nodes over a designated time period. Likewise a 1MW FGR is a forward contract entitling its holder to receive the stream of shadow prices on a specific flowgate over a designated time period. Hence, the above fundamental relationship can be extended to relate point to point FTR obligations and FGRs implying that a point to point FTR obligation may be viewed as a portfolio of FGRs weighted by the corresponding PTDF differences. This relationship, however, becomes more complicated with respect to point to point FTR options. A simplistic approximation, suggested by O'Neill *et al* (2002), is to calculate the payoff (or price) of a point to point FTR option as the partial summation of the weighted FGR payoffs (or prices) over flowgates for which the PTDF difference in the above formula is positive. Since shadow prices and hence FGR payoffs are nonnegative such an approximation ensure a nonnegative payoff for the point to point FTR option. Such a calculation, however, overcompensates point to point FTR options in cases where the payoff is positive but reduced by the presence of "couterflow" branches. Unfortunately, the decomposition of point to point FTR options into FGRs enabled by the above approximation is essential for a joint auction that offers the different instruments simultaneously.

3. MANAGING CONGESTION RISK

In LMP based markets, energy transactions in the Day Ahead market are exposed to congestion rents that are determined as the LMP difference between the injection and withdrawal nodes. A trader buying energy at one location to be delivered at another location, incurs such congestion rents as the difference between the selling price of energy at the source and the buying price at the delivery point when the transactions are cleared through the ISO market. Alternatively, if the delivery is scheduled as a firm bilateral transaction then it is subject to a congestion charge imposed by the ISO that equals to the LMP difference between the injection and withdrawal locations. In either case a trader can hedge its exposure to the congestion charges by acquiring financial transmission rights.

In view of the fundamental relationship between point to point FTRs and FGRs explained above, a trader could achieve the same protection against congestion charges provided by a point to point FTR obligation by buying the equivalent portfolio of FGRs. To illustrate this equivalence consider the three node network in Figure 2 with identical susceptances for all three lines and flow limits as indicated on the respective lines.

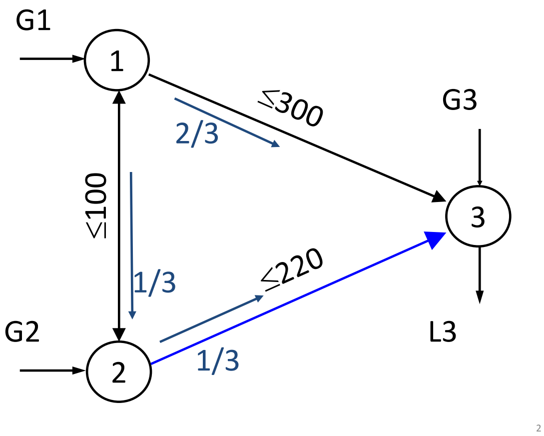


Figure 2: Three node example

Injecting 1MW at node 1 and withdrawing it at node 3 produces (2/3)MW flow on the line 1 to 3 and (1/3)MW flow on the lines 1 to 2 and 2 to 3. Suppose that G1 has a bilateral contract with L3 to deliver 150MW and wishes to hedge the contract against congestion charges. This can be done by procuring 150MW FTR obligation from node 1 to 3. In real time the congestion rent charged to the bilateral transaction is the nodal price difference between the two nodes times the 150MW transacted. That amounts is also the settlement payment for the 150MW FTR from node 1 to 3. Thus the FTR settlement exactly offsets the congestion charge. Alternatively, the bilateral transaction can be hedged against congestion by procuring a portfolio of FGRs as follows: 100MW FGR on line 1 to 3, 50MW FGR on line 1 to 2 and 50MW FGR on line 2 to 3. Each FGR is paid in real time the corresponding shadow price per MW.

Assume that only the line 2 to 3 is congested then the shadow price on the other two lines is zero and the settlement payment for the above FGR portfolio is $50 \cdot SP_{23}$ but from the fundamental relationship between nodal prices and shadow prices on transmission lines we know that $LMP_3 - LMP_1 = \frac{1}{3} SP_{23}$. Hence the settlement payment for the FGR portfolio is $50 \cdot 3 \cdot (LMP_3 - LMP_1)$ which is identical to the settlement for the FTR from node 1 to 3 both of which equal the congestion charge for the bilateral transaction.

The difference between using FTRs or FGRs in hedging congestion risk arises when considering changes in the network topology which will produce changes in the PTDFs such changes may result from contingencies or deliberate control actions switching lines in or out. Whether FTRs or FGRs are used to define property rights and hedging mechanisms has also implication regarding the extend to which the physical capacity of the network can be fully subscribed and the ability of market participants to fully hedged their energy transactions. Since the payoff of a point to point FTR obligation is based on the actual LMP difference which is also used in computing the congestion rents, a 1MW FTR obligation between two nodes provides a perfect hedge against the congestion charges imposed on a 1MW energy transaction between the same nodes. Such a hedge provides insurance against congestion risk resulting from changes in dispatch patterns and LMPs as well as changes in the network topology, including line capacity ratings and the PTDFs.

The availability of perfect hedging instruments does not imply, however that all transactions that can be accommodated in real time by the physical system can be hedged while assuring that the real time congestion revenues suffice to pay off the settlements to all outstanding FTRs (i.e., revenue adequacy). As discussed below, the conditions that will guarantee revenue adequacy result in unsubscribed flowgate capacity which in turn can lead to congestion revenue surplus. Such surplus indicates that some energy transactions could not be fully hedged. When FGRs portfolios are used to hedge congestion risk associated with energy transactions, it is the responsibility of the FGRs holder to assemble a portfolio that synthesizes the LMP differences that are used to compute congestion charges, such a portfolio protects the holder against fluctuations in shadow prices on the flowgates and against changes in the flowgate capacity ratings but does not provide insurance against variation in the PTDFs. So it is the responsibility of the insured to track such variations to ensure that the FGR portfolio produces sufficient settlement revenue to cover the congestion charges that are based on the LMP differences.

On the other hand, FGR allocations are based on the full flowgate capacity as opposed to FTR allocation that only subscribes the flowgate capacity corresponding to the allocated FTRs. Thus, the entire wire capacity can be subscribed through FGRs and as long as flowgate capacities are not reduced, the congestion revenues (which can be assigned to flowgates based on the real time PTDFs), will match the FGR settlements (i.e., revenue adequacy is automatically guaranteed). Another consideration is the need for centralized coordination in issuing and secondary trading of the various forms of financial transmission rights. As will be discussed below, Assuring revenue adequacy for point to point FTRs requires central coordination since available transmission capacity between any two nodes depends on the entire constellation of other point to point FTRs issued.

Consequently, the issue of point to point FTRs is always done by a central authority such as an ISO and any secondary trading takes place through centrally coordinated reconfiguration auctions. By contrast, since FGRs are only tied to specific flowgate capacities, they can be issued by multiple entities owning specific flowgate assets or producing counterflow and can be traded independently in secondary markets. This issue has come up, for instance, in the European Union where congestion revenues on international interconnect flowgates are collected by the interconnected countries which are also vested with the right to issue long term contracts for the use of such facilities.

Arguments in favor and against employing FGRs in practice as hedges against congestion risk can be found in Chao *et. al.* (2000) and Ruff (2001). In our subsequent discussion we will not duel any further on this debate and only exploit the conceptual interpretation of FTRs as an FGR portfolio.

4. REVENUE ADEQUACY AND SIMULTANEOUS FEASIBILITY

Hogan (1992) has shown that if the outstanding FTRs satisfy a “simultaneous feasibility test” (SFT) and the network topology is fixed then the FTR market is ”revenue adequate”. Revenue adequacy means that congestion revenues and merchandising surplus (i.e., the difference between the buying cost and the sales revenues for energy traded through the pool) collected by the system operator from bilateral transactions and local sales and purchases at the LMPs, will cover the FTR settlements. The SFT requires that if all the FTRs were exercised simultaneously as physical bilateral transactions then the transmission flow constraints would not be violated.

In FTR auctions bidders submit bids for specific FTRs and the ISO selects winning bids by treating FTR bids as proposed schedules using a security constrained OPF that maximizes the FTR auction bid value. These constraints are also imposed if any portion of the FTRs is being allocated based on historical use or other allocation criteria. As mention above, the hypothetical dispatch (referred to as the FTR point) corresponding to simultaneous bilateral schedules replicating all outstanding FTRs must meet all security and flow constraints i.e. the grid must be able to support all the bilateral transactions covered by the FTRs. The auction produces a set of winning bids and uniform clearing prices for each pair of nodes that equal to the LMP differences of the auction OPF.

Clearly, the FTR point characterizing the mix of awarded FTRs, may differ from real time dispatch. However, but if the topology hasn't changed the FTR point represents a feasible but not necessarily optimal dispatch. Hence, if the nomogram is convex, then the congestion revenues will be sufficient to cover the FTR settlements. This follows from a theoretical argument based on duality of linear programs, showing that minimum cost dispatch is equivalent to maximizing congestion revenues.

Figure 3 below illustrates the nomogram representing feasible dispatch for the three node DC system introduced earlier with identical susceptances for all lines but different flow limits as shown. The vertical axis of the graph represents injection at node 2 and withdrawal at node 3 while the horizontal axis represent injection at node 1 and withdrawal at node 3. The feasible region given the flow constraints is characterized by a convex polyhedron defined by the system of linear inequality constraints implied by Kirchhoff's law and the flow limits on the lines. The same constraints also characterize the feasible set of FTRs from node 1 to node 3 and from node 2 to node 3 that will meet the SFT described above. The facets of the polyhedron correspond to the flow capacity constraints and adjusting these capacities is represented by a parallel shift of these facets as shown for line 2 to 3.

We note that the system can accommodate up to 400MW transaction from node 1 to 3 if there is a 100MW transaction from node 2 to node 3 which produces counterflow on the congested link from node 1 to node 2. In the absence of such counterflow, the system can only accommodate a 300MW transaction from node 1 to node 3. In the context of the SFT, reliance on conterflow translates to reliance on an FTR obligation with a negative real time settlement which will supplement the congestion revenues to produce sufficient income for FTR payoffs.

FTRs with an expected negative real time settlement have negative value and those who are willing to assume such an obligation would expect to be paid upfront and will submit negative bids (i.e. offers) in the FTR auction to undertake the obligation. If the holder of such an FTR obligation from node 2 to node 3 actually executes the corresponding transaction in real time, by injecting power at node 2 and taking it out at node 3, it produces counterflow for which it will collect negative real time congestion charges (i.e., counterflow payments) that will exactly offset the negative settlement of the FTR obligation from node 2 to node 3. In such a case, the auction income from taking on an FTR obligation with negative payoff is a net gain to the FTR holder which can be used, to subsidize a forward contract at a price below marginal production cost if executing the transaction produces couterflow that will offset the negative FTR settlement.

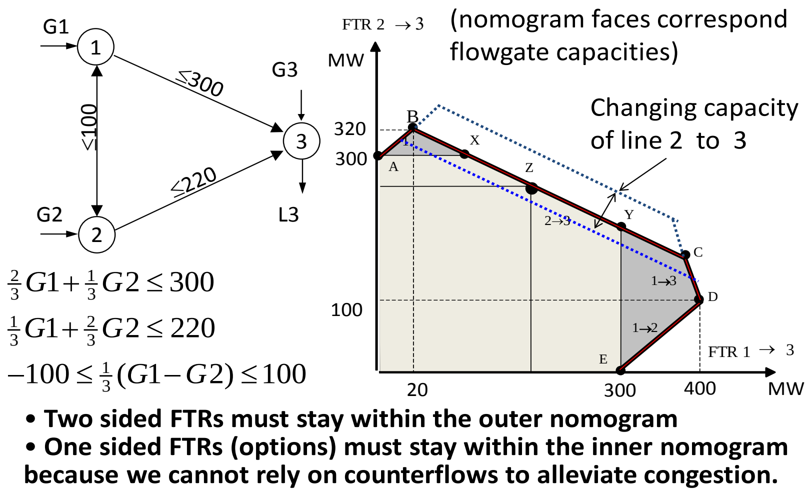


Figure 3: Feasibility region of FTR options and obligations and the effect of flowgate capacity rating

However, undertaking such an FTR obligation entails exposure to performance risk in case that the FTR holder cannot execute the transaction due to a generator outage, for instance. To avoid such exposure, market participant would prefer (assuming all else being equal) FTR options that protects them from potential liability that comes with an FTR obligation. Issuing FTR options rather then obligations implies, however, that the ISO cannot rely in the SFT on counterflows and cannot rely on the supplemental revenue produced by FTR obligations with negative settlemet. Hence, the feasible region for FTR options in the case depicted by Figure 3 is the chopped off light portion of the nomogram. While FTR options are attractive from a risk management perspective their use is limited since they severely limit the simultaneously feasible FTRs that can be issued and they turn out to be expensive as compared to the two sided FTR obligations. One of the important uses of FTR options is to convert historical entitlements to physical transmission rights held by MUNIs, for instance, (which are inherently options) to financial transmission rights.

To illustrate how FTRs can facilitate efficient forward energy trading, lets assume that the marginal cost of G1 is \$30/MWh the marginal cost of G2 is \$45/MWh and of G3 is \$100/MWh. The load at L3 is 500MW and the capacities of all three generators exceeds 500MW. The optimal dispatch for this case is at point D of the nomogram in Figure 3, which corresponds to supplying the load at L3 with 400MW from G1 and 100MW from G2. The corresponding LMPs at nodes 1,2,3 are \$30/MWh, \$45/MWh and \$40/MWh respectively. Both, line 1 to 3 and line 1 to 2 are operating at the flow limit with corresponding shadow prices of \$5/MW/h and \$20/MW/h, respectively. If the optimal dispatch and LMPs are forecasted correctly, the FTR auction will clear with 100MW FTR obligations from node 1 to 3 awarded at \$10/MW/h and 400MW FTR obligation from 2 to 3 awarded at -\$5/MW/h (i.e. the bidder gets paid for assuming the obligation).

Both G1 and G2 can enter into forward contracts to deliver energy to L3 at \$40/MWh which for G1 would result in a gain of \$10/MWh and for G2 in a loss of \$5/MWh. G1 can then hedge its exposure to real time congestion charges by using its forward contract surplus to buy FTR obligations from node 1 to 3 in an amount matching the forward energy contract. Likewise, G2 can offset the forward contract deficit with expected real time counterflow payments or lock in these payments by taking on FTR obligations from node 2 to 3 so as to match the forward contract quantity. The system operator collects from G1 congestion rents for 400MW from node 1 to 3 in the amount of \$10/MWh (based on the LMP difference) and pays to G2 \$5/MWh for 100MW of counterflow totaling \$3500/h. The FTR settlement amount to \$10/MWh times 400MW for FTRs from node 1 to 3 less the amount collected from the FTRs from node 2 to 3 of \$5/MWh times 100MW, adding up to \$3500/h. So in this case the ISO breaks even.

Suppose, however, that the real time LMPs were not forecasted correctly in the FTR auction and the bids resulted in an FTR point other than point D on the nomogram. Specifically, assume that the FTR auction awards corresponded to point E on the nomogram with 300MW FTRs from node 1 to 3 and no FTRs from node 2 to 3. Then, the FTR settlement amounts to 300x10 =\$3000/h resulting in a congestion revenue surplus of \$500/h. In general the real time settlement for any feasible FTR award combination will be less than or equal to the congestion revenue corresponding to the optimal dispatch point D.

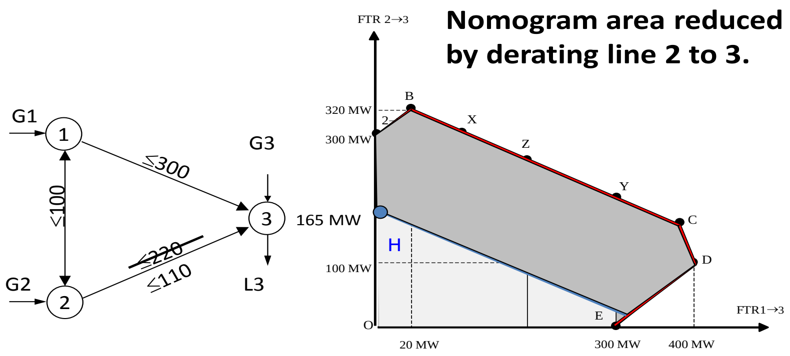
FGRs can be used in a similar way to the above although achieving proper hedging places more burden on energy traders. In an FGR auction all the FGRs corresponding to the lines capacities rating (in both directions) are being allocated. However, if the dispatch is correctly forecasted in the FGR auction, only the FGRs on the line from node 1 to 3 and from node 1 to 2 have positive clearing prices which in our example equal to \$5/MW/h and \$20/MW/h respectively. The total auction revenue will be the same as in the corresponding FTR auction totaling 5x300+20x100=10x400-5x100=\$3500/h. as in the case of FTRs, G1 and G2 can hedge their forward energy contracts to deliver energy to L3 at \$40/MWh. In this case G2 would buy (100/3)MW FGRs on line 1 to 3 (backed by wire capacity) and sell (100/3)MW FGRs on line 1 to 2 (backed by counterflow it expects to produce) at a total gain of (100/3)x(20-5)=500/h which exactly offsets its forward energy contract deficit. G1 could buy (800/3)MW FGRs on line 1 to 3 (backed by wire capacity) and (400/3)MW FGRs on line 1 to 2 of which 100MW is backed by wire capacity and (100/3)MW is backed by counterflow.

The total FGR cost to G1 is (800/3)x5+(400/3)x20=\$4000/h which exactly matches its forward energy contract surplus. These FGR procurements match the expected flows induced by the transactions corresponding to the forward contracts entered into by G1 and G2 (based on the system PTDFs). In real time G1 pays as before congestion charges of \$10/MWh for 400MW it delivers to L3 and receives FGR settlements (based on shadow prices) of (800/3)x5+(400/3)x20=\$4000/h which exactly offsets the congestion charges. Likewise G2 collects \$500 in counterflow payments from the ISO which cover its net FGR settlement liability resulting from \$5/MW/h income for (100/3)MW FGRs it sold on line 1 to 3 less its \$20/MW/h payout for its short position on (100/3)MW FGR on line 2 to 3, totaling \$500/h. In the above setting the ISO always breaks even since the wires capacity is fully sold while both the congestion rents and the FGR settlements are based on the same flows and shadow prices.

The revenue surplus we have identified when FTRs are being used results from the fact that an FTR auction only allocates flowgate capacity corresponding to the FTRs that are sold leaving the remaining flowgate capacity in the hands of the ISO. Hence when the real time dispatch differs from the FTR point, unsold flowgate capacity may become valuable and the congestion revenue corresponding to that unsold capacity translates into a revenue surplus for the ISO. For instance in Figure 3, if FTRs awarded in the auction correspond to point E, then the constraint on line 1 to 3 is not binding and 100MW of flowgate capacity on line 1 to 3 remains unsold. Then when the real time dispatch moves to point D on the nomogram and the shadow price on line 1 to 3 goes to \$5/MW/h, the congestion rents on that unsold flowgate capacity retained by the ISO produce a revenue surplus of \$500/h.

5. Line Derating and Topology Changes

Flowgate capacity ratings will affect the feasible SFT nomogram as illustrated in Figure 3 for a three node DC network. Consequently, if in real time operation, a flowgate rating is decreased from what was assumed in the SFT or if the flowgate failed due to a contingency, then, the FTR operating point may not be feasible in the real dispatch topology as shown in Figure 4.



If FTRs are awarded based on Pt. B or D. and RT dispatch is at Pt. H, then congestion revenues will not cover FTR settlements.

Figure 4: The effect of derating flowgate capacity

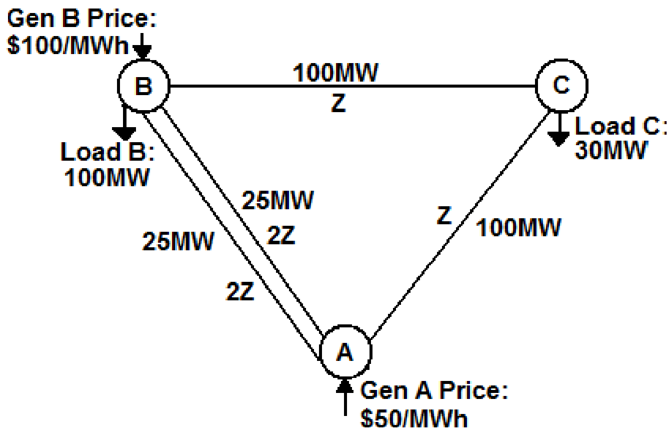


Figure 5: Revenue adequacy example

Such line derating may result in revenue shortfall, i.e., the congestion rents that are based on the real time LMP differences may not suffice to cover the settlements to all outstanding FTRs. To illustrate such revenue shortfall more explicitly consider a three node example introduced by Hedman *et al.* (2011) and shown in Figure 5 . In this example FTRs are allocated based on an SFT which assumes the depicted topology. In particular 60MW FTR obligations from node A to B and 30MW FTR obligation from node A to C have been sold through an auction (or allocated by any other means).

The feasible region for the SFT is characterized by the set of linear inequalities:

$$\begin{gathered}
-50 \le \frac{2}{3}AB + \frac{1}{3}AC \le 50 \\
-100 \le \frac{1}{3}AB + \frac{2}{3}AC \le 100 \\
-100 \le \frac{1}{3}AB - \frac{1}{3}AC \le 100 \\
-100 \le AB + AC \le 100 \\
-100 \le AB \le 100
\end{gathered}$$

This region is illustrated in Figure 6 as the triangle consisting of areas 1, 2 and 4. The outstanding FTRs represent a point on the boundary of the feasible region (depicted by the gray square) and hence they satisfy the SFT for this topology.

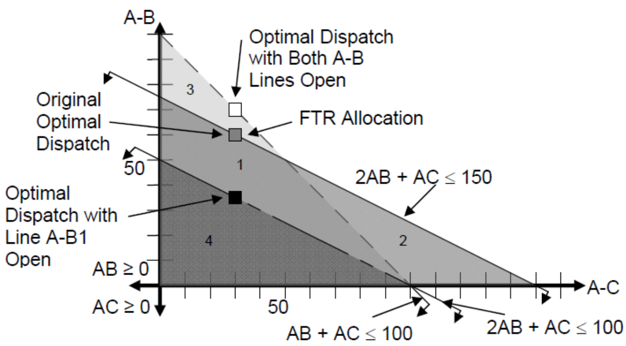


Figure 6: Feasible region for different topologies

If the topology doesn't change then the optimal dispatch coincides with the FTR allocation and hence the corresponding congestion revenues exactly cover the payments to FTR holders. Suppose, however, that in operation one of the lines between node A and B fails. Such a contingency will shrink the feasible region to area 4 in Fig. 5 which is represented by the inequalities:

$$-25 \le \frac{1}{2}AB + \frac{1}{4}AC \le 25$$
$$-100 \le \frac{1}{2}AB + \frac{3}{4}AC \le 100$$
$$-100 \le \frac{1}{2}AB - \frac{1}{4}AC \le 100$$

Thus, the outstanding FTRs are no longer simultaneously feasible under the new topology.

The optimal dispatch under the above contingency is represented by the black square in Figure 6. Tables 1, 2 and 3 below show that the congestion revenues corresponding to this dispatch fall short of covering the settlement payments to the FTR holders. In this case the contingency affected the generators' output and flows but did not affect the LMPs and hence the FTR payments. Specifically, the congestion revenues dropped from $3,750 to $2,500 while the FTR settlement remains $3,750 resulting in a shortfall of $1,250.

Table 1: Optimal dispatch results with all lines in

Node	Gen output	LMP	Gen Cost	Trans-action	MW	Cong. Rent
A	90MW	$50/MWh	$4,500	A – B	60MW	$3,000
B	40MW	$100/MWh	$4,000	A – C	30MW	$750
C	0MW	$75/MWh	$0	**Congestion Rent:**		**$3,750**
Total Generation Cost:			**$8,500**			

Table 2: Optimal dispatch results with one line A-B out

Node	Gen output	LMP	Gen Cost	Trans-action	MW	Cong. Rent
A	65MW	$50/MWh	$3,250	A – B	35MW	$1,750
B	65MW	$100/MWh	$6,500	A – C	30MW	$750
C	0MW	$75/MWh	$0	**Congestion Rent:**		**$2,500**
Total Generation Cost:			**$9,750**			

Table 3: FTR settlements

Source to Sink:	FTR Quantity:	FTR Settlements (All lines in)	FTR Settlements (One line A-B out):
A to B	60MW	$3,000 (LMP gap: $50/MWh)	$3,000 (LMP gap: $50/MWh)
A to C	30MW	$750 (LMP gap: $25/MWh)	$750 (LMP gap: $50/MWh)
Total FTR Settlements:		**$3,750**	**$3,750**

Suprisingly, revenue adequacy can be restored and generation cost reduced in this case by switching off the other line between nodes A and B. The feasible region corresponding to the topology with both lines between node A and B out is defined by the constraint:

$$AB + AC \leq 100$$

Since both A to B and A to C transactions must share the line between A and C. Hence, the feasible region is now represented by the triangle consisting of areas 1,3 and 4 in Figure 6 whereas the optimal dispatch moved from the black rectangle to the white rectangle. Furthermore, the gray rectangle representing the outstanding FTRs is now within the feasible region and can, therefore, be interpreted as a suboptimal feasible dispatch. Since an optimal dispatch solution also maximizes congestion rents (by duality theory of linear programming), it follows that the congestion rents exceed the FTR settlements which equal to the congestion rents corresponding to a feasible suboptimal dispatch. The above observations are verified numerically by the results in Tables 4 and 5. The optimal dispatch results with both lines between node A and B out are summarized in Table 4 and the corresponding FTR settlements are given in Table 5. We note that generation cost dropped to $8000 which is below the optimal dispatch with all lines in, while congestion revenues increased to $5,000 which is sufficient to cover the $4,500 FTR settlement payments.

Table 4: Optimal dispatch results with two lines A-B out

Node	**Gen output**	**LMP**	**Gen Cost**	**Trnsa-acion**	**MW**	**Cong. Rent**
A	100MW	$50/MWh	$5,000	A – B	70MW	$3,500
B	30MW	$100/MWh	$3,000	A – C	30MW	$1,500
C	0MW	$100/MWh	$0	**Congestion Rent:**		**$5,000**
Total Generation Cost:			**$8,000**			

Table 5: FTR Settlements with the two lines A-B out

Source to Sink:	FTR Quanti-ty:	FTR Settlements (Both lines A-B Open):
A to B	60MW	$3,000 (LMP gap: $50/MWh)
A to C	30MW	$1,500 (LMP gap: $50/MWh)
Total FTR Settlements:		**$4,500**

6. Allocating Revenue Shortfalls

When a revenue shortfall occurs, i.e. congestion revenues cannot cover the settlement payments to FTR holders, the system operators must make up the difference. The various approaches adopted by system operators in the US for addressing such revenue shortfalls include:

- Full payment to FTRs based on nodal prices and uplift of the shortfall to sellers or buyers of energy (full funding approach)
- Prorate settlement to all FTRs to cover shortfall (“haircut” approach)
- Intertemporal smoothing of congestion revenue accounting by carrying over revenue surpluses and shortfall over an extended time period.
- Prorate settlement to FTRs based on impact of derated flowgates
- Full funding of FTRs and assignment of shortfall to owners of derated flowgates.

The first three alternatives socialize the cost of derated lines to energy sellers or buyers or to the FTR holders or across time periods. In the extreme case when a derated line is radial such socialization is vulnerable to gaming. An FTR holder on a derated but underutilized radial line has the incentive to congest that line though fictitious transactions in order to capture FTR revenues. The last two alternatives, which we advocate in this paper, directly assigns shortfalls to users or owners of derated flowgates. An important motivation for such an approach is to prevent potential gaming through overscheduling intended to induce congestion that will increase the payoff on certain FTRs. To illustrate such direct assignment consider the three node example in Figure 2. In that example 1MW FTR from node 1 to 3 contains 1/3 MW flow on line 2 to 3, whereas 1 MW FTR from node 2 to 3 contains 2/3 MW flow on line 2 to 3. Thus, if line 2 to 3 is derated by 50% the congestion revenue shortfall will be 110 times the shadow price SP_{23} on line 2 to 3.

The aforementioned shortfall can be assigned to the line owner while preserving full funding of the outstanding FTRs. Alternatively it can be assigned to the FTRs by reducing their settlement payment in accordance to the proportion of the derated line flow that they contain. Specifically since the capacity of line 2 to 3 was reduced by 50%, The payment to a 1MW FTR from node 1 to 3 is reduced by 0.5x(1/3)x SP_{23} and the payment to a 1MW FTR from node 2 to 3 is reduced by 0.5x(2/3)x SP_{23}. The SFT requires that the number of FTRs from node 1 to 3 times 1/3 plus the number of FTRs from node 2 to 3 times 2/3 does exceed the thermal limit of line 2 to 3 which is 220MW (and it equals to that limit when the shadow price SP_{23} is positive.) Hence, the reductions of FTR settlement payments above adds up exactly to 110x SP_{23} which is the revenue shortfall due to the derating of line 2 to 3.

Consider now the case when more than one line is derated. Suppose that line 2 to 3 is derated by 50% and line 1 to 3 is derated by 20%. Direct assignment the of revenue shortfall will again reduce the settlement payments to each FTR based on its flow share on each derated line. Thus payments to 1MW FTR from node 1 to 3 is reduced by 0.5x(1/3)x SP_{23} +0.2x(2/3)x SP_{13}. Likewise payments to 1MW of FTR from node 2 to 3 is reduced by 0.5x(2/3)x SP_{23} +0.2x(1/3)x SP_{13}. An intuitive analogy to the above approach is to think of FGRs as stocks and of FTRs as mutual funds which contain the various FGRs in proportions reflecting the corresponding PTDFs. When a line is derated by 50% it is equivalent in our analogy to a stock loosing half its value. In the financial analogy it is natural that when a stock loses part of its value then the different mutual funds containing that stock will be impacted in proportion to their holdings of that stock. It would seem unreasonable to suggest that the loss of a stock would be born equally by all mutual funds offered by a brokerage house regardless of the holdings of the stock in each fund. Likewise it is natural and fair to allocate the revenue shortfall due to derating of a line according to the flow impact of each FTR on the derated line.

7. EXPANDING THE FTR FEASIBLE REGION VIA SHORT FGRS

While derating line capacities reduces the feasible set of FTRs that the network could support without revenue shortfalls, increasing line capacity ratings will increase the set of FTRs that can be awarded in the auction as shown in Figure 7 below. Such an increase could result from a physical change in line capacity due to an upgrade of a line or improved maintenance. Alternatively, an increase in line capacity used for the purpose of the SFT can be "virtual" and supported by short positions on FGRs, just as an increased number of available FTRs between two points can be underwritten by counterflow commitments. A short position on an FGR amounts to an obligation to either increase the flowgate capacity or underwrite the settlement cost of the added FTRs. The holder of a 1MW short FGR position on a particular line is paid the shadow price on that line in the SFT power flow calculation and is liable for the shadow price on that line in real time. The payment received by such a short position holder in the FTR auction is financed by the revenue from the additional FTRs that can be sold due to the increase in the SFT feasible nomogram.

The real time settlement paid by the short FGR holder supplements the congestion revenues and will cover any FTR revenues shortfall resulting from the oversold FTRs. If the line for which the short FGR position was issued is not congested in real time then the holder of that position gets to pocket the auction revenue for underwriting that position. To illustrate, suppose that the auction clearing price on both FTRs depicted along the axis in Fig. 6 (Node 2 to 3 and node 1 to 3) is \$10/MW/hour, then the corresponding shadow price on line 2 to 3 is also \$10/MW/hour. A short position of 55MW on line 2 to 3 will earn its underwriter \$550/hour. Such a short position expands the feasible region in the SFT as shown in Figure 7 and changes the results of the FTR auction clearing so that the number of FTRs awarded from node 2 to 3 increase from 140MW to 250MW while the number of FTRs awarded from node 1 to node 3 is reduced from 380 to 325. In this particular case the expansion of the feasible region did not change the FTR clearing prices only their awarded quantities. Thus the net gain in FTR auction revenue is 10x(250-140)+10x(325-380)=\$550/h which is exactly the amount paid by the auctioneer for the 55MW short FGRs. In real time the underwriter of the short FGRs is liable for 55x SP_{23} which should cover any revenue shortfall resulting for the incremental FTRs awarded against the short FGR position. However, if the line 2 to 3 turns not to be congested SP_{23} is zero and no revenue shortfall occurs so that the short FGR underwriter got to pocket the short position income.

Short FGR positions can be assumed by any entity that wishes to bet against certain lines being congested. However, such instruments are ideally suited for transmission owners (TOs) who are in a position to upgrade the line or maintain it so as to increase its real time rating. Thus, short flowgate positions provide incentives for incremental improvements and maintenance (e.g. vegetation control) that can enhance real time transmission capacity. If a line is not binding in real time then the TO retains the auction income for the short position taken. Similarly, short positions on long term flowgate rights can finance planned upgrades and investments that will alleviate congestion on the shorted flowgates while enabling the ISO to issue long term FTRs against such upgrades.

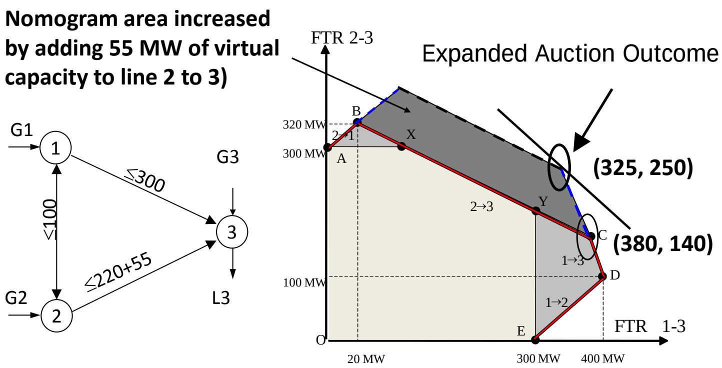


Figure 7: Expanding FTR Feasibility with Short FGR Positions

Like in every performance based incentive scheme, performance must be measured and verified against a credible and stable yardstick (e.g. PBR scheme for NGC in the UK). TOs should get assurances that they will not face a moving target and improvements they make will not change the nominal line rating used in subsequent FTR auctions. Furthermore, active participation by TOs in FTR trading must be regulated to insure correct incentives (e.g. long positions by TOs should not be allowed since they create incentives to restrict flow).

8. Conclusion

Just as point to point FTRs provide a convenient hedge against congestion charge risk for point to point energy transactions, FGRs are convenient instruments for managing flowgate capacity risk and reward investment in such capacity. When a revenue shortfall occurs allocating the losses based on the imbedded FGR content of various FTRs or directly to the TO of the affected flowgate, eliminates socialization that can cause inefficiencies and gaming. Conversely FGR short position that expand possible FTR awards provide a useful means for financing investment and reward performance that improves flowgate ratings. These positions also allow private parties to underwrite FTR revenue shortfalls due to flowgate capacity risk. Such activities, however, must be carefully regulated and monitored to avoid perverse incentives and abuses.

Acknowledgement:

This chapter is intended as a tutorial and review of previous work. Much of the text and most of the figures used are adopted from a joint conference paper with Kory Hedman, published online in the proceeding for the IREP 2010 symposium Oren and Hedman (2010). I also adopted material, especially the example in Figure 1, that was developed by Fernando Alvarado as part of a tutorial we jointly presented on financial transmission rights in the year 2000. This work was supported by the National Science Foundation Grant IIP-0969016 and by the Power Systems Engineering Research Center.

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