Managing Congestion Risk in Electricity Markets*

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Abstract
There is a clear recognition that congestion is a major source of risk to a market participant's revenue under LMP rules. In northeast US, FTR has been utilized as a hedge tool to manage congestion risk. ISOs are in charge of auctioning transmission capacity to market participants interested in buying transmission rights. The revenue collected form FTR auctions is used to pay transmission owners. Generators and loads pay congestion through LMP; ISOs collect congestion revenue from them and pay FTR holders. Under perfect conditions all pieces fit perfectly, however, in real life implementation we have observed some discrepancies. In this paper, mathematical models and academic numerical examples are used to show some of the risks present in this process.

I Introduction

The advent of deregulation in the electricity industry created an increment not only in number but also in volume of transactions among market participants. In order to accommodate them in a market-based manner, and at the same time to consider relevant physical constraints, it was necessary to price electricity at the location level instead of at the control area level. Different price methodologies were designed with this purpose. In the Northeast US, in particular, Locational Marginal Pricing (LMP) has been the price methodology employed to manage electricity market's transactions.

There is a clear recognition that congestion is a major source of risk to a market participant's revenues under LMP rules. The capability to deal with congestion related risks requires usage of congestion hedge tools. Financial Transmission Rights (FTR) has been used as a feasible solution to this problem. FTR is a financial hedge which provides to the FTR's holder the reimbursement of congestion charges, providing price certainty to transmission customers.

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Under ideal conditions, all economic incentives match perfectly; however, in real life implementations we have observed some deviations from theory which created the interest for writing this article.

Functional aspects of electricity markets and LMP are presented in Section II. The concept of FTR and its importance as a tool for managing congestion risk is discussed in Section III. FTR auction mathematical formulation is presented in Section IV. Numerical examples and further discussions are illustrated in Sections V and VI.

II Locational marginal pricing (LMP)

The standard bid-based, security constrained, economic dispatch optimization problem for a snapshot of time *t* can be formulated as follows[1]:

$$\underset{Pgi}{Min} \sum_i MC_i(Pg_i)Pg_i \qquad (1)$$

Subject to:

$$\sum_i Pg_i = \sum_i Pd_i \qquad (\lambda) \qquad (2)$$

$$Fl = \sum_i A_{i,l}(Pg_i - Pd_i) \le Fl^{\max} \qquad \forall l \qquad (\mu l) \qquad (3)$$

$$Pg_i^{\min} \le Pg_i \le Pg_i^{\max} \qquad \forall i \qquad (\gamma_i^{\min}, \gamma_i^{\max}) \qquad (4)$$

$MC_i(Pg_i)$ is marginal cost of production or bid function for generator *i*, Pg_i and Pd_i are generation and demand respectively, and Fl is power flow on line *l*[2]. After solving this optimization problem, the standard locational marginal price for location *i* and time *t* is calculated as

$$\rho_i = \lambda + \sum_l \mu l A_{i,l} \qquad (5)$$

Where λ is shadow price associated with equality constraint (2), μl is shadow price associated with transmission constraint for line *l* (3), and Ail is sensitivity of power flow on line *l* due to injection at bus *i*.

The price spread between two locations can be calculated as

[1] Our paper is only focused on transmission congestion and congestion risk; therefore a lossless DC load flow model is used. Operating reserve constraints, voltage constraints, inter-temporal constraints (e.g. ramping, minimum time in operation, minimum downtime) are not modeled. For simplicity, variable time *t* is not included in equations.

[2] For purposes of simplicity, we use index *l* to identify both cases, base and contingency.

$$\rho_j - \rho_i = \sum_l \mu l \left(A_{l,j} - A_{l,i}\right), \qquad (6)$$

which represents congestion risk between *i* and *j*. It is important to emphasize that this spread is only function of μl for a particular snapshot of topology.

This price spread can be considerable when transmission shadow price is different from zero (congestion), and difference in sensitivities in absolute value is greater than zero (electrically close to congested element). The value of μl is always negative or zero. It is negative because an increment in transmission capacity $Fl^{\max}$ results in reduction of system's total cost (objective function (1)). μl's value is function of redispatch cost incurred to solve the particular binding constraint *l*. $A_{i,l}$'s value is function of transmission topology. $\left(A_{j,l} - A_{i,l}\right)$ is negative when an injection at *i* and withdraw at *j* contributes with power flow on line *l* in the same direction as the congestion, and takes positive value when creates counter flow.

III Congestion risk

A market participant that has a contract with delivery and compensation in different locations under LMP rules is subject to congestion risk. However, the same market participant with a proper hedge tool between those locations and for the same capacity and period of time, should have its exposure reduced.

Let us examine the following example. *j* represents a location where there is a liquid forward market, e.g. a Hub, and *i* is a location where a generator produces and sells power in real time. If the generator sells forward power X_F in t_0 for delivery between times *t* and *T*, at price F_j; then during delivery time, it buys back the forward position X_F at real time price (assuming that this contract settles in real time) ρ_j; finally it generates in real time X_{RT} and sells its production at real time price ρ_i. Under this setup, the generator's revenue results

$$\Re_T = \sum_t \left(X_F F_j - X_F \rho_j + X_{RT} \rho_i\right) = \sum_t \left(X_F F_j + \left(X_{RT} \rho_i - X_F \rho_j\right)\right) \qquad (7)$$

Assuming no volumetric risk $X_F = X_{RT}$, then

$$\Re_T = X_{RT} \sum_t \left(F_j + \left(\rho_i - \rho_j\right)\right), \qquad (8)$$

and without congestion risk $\rho_i = \rho_j$,

$$\Re_T = X_{RT} \sum_t F_j = X_{RT} F_j T \,. \qquad (9)$$

Therefore, the generator produces and sells power in real time and receives forward price fixed in t_0 for it. This price certainty is one of the major incentives for participating in forward markets.

However, if there is congestion, both prices are not equal anymore $\rho_i \neq \rho_j$, and in particular if $\rho_i < \rho_j$ the generator is going to lose revenue (with respect to the revenue obtained under unconstrained scenario (9))

$$\sum_t X_{RT}\left(\rho_j - \rho_i\right)_t = \sum_t X_{RT}\left(\sum_l \mu l\left(A_{j,l} - A_{i.l}\right)\right)_t . \qquad (10)$$

Similar situation takes place when a consumer buys forward power in location *j* and consumes it in real time in location *i*; or when two parties sign a bilateral contract with production and consumption at different locations and priced at a hub location.

For these reasons, it is necessary to have a hedge tool to manage congestion risks. In northeast US, Financial Transmission Right (FTR)[3] has been used as a feasible solution to this problem.

Financial Transmission Right for path *k*, $FTR_k\left(i, j, MW_k, T\right)$, between locations *i* and *j*, for MW_k capacity, and settlement period T, is the right to receive during T the sum of the congestion charge. Mathematically,

$$FTR_k\left(i, j, MW_k, T\right) = \sum_t MW_k\left(\rho_j - \rho_i\right)_t = \sum_t MW_k\left(\sum_l \mu l\left(A_{j.l} - A_{i.l}\right)\right)_t \qquad (11)$$

which is exactly the exposure of market participant *i* analyzed in the example above (10), assuming $X_F = X_{RT} = MW_k$. The analysis of volumetric risk, $X_F \neq X_{RT} \neq MW_k$, is not analyzed here. In reality, FTR is a Day Ahead financial tool, but it can be moved to Real Time market through virtual bidding, e.g. INC source *i* and DEC sink *j* for path *k*.

IV FTR auction

The standard bid-based, FTR auction optimization problem for a snapshot of time *t* can be formulated as follows.

$$\underset{MW_k}{Max} \sum_k Bid_k MW_k \qquad (12)$$

Subject to:

$$0 \leq MW_k \leq MW_k^{\max} \qquad \forall k \qquad \left(\theta_k^{\min}, \theta_k^{\max}\right) \qquad (13)$$

$$Fl^* = \sum_k MW_k PTDF_{k,l^*} \leq Fl^{*\max} \qquad \forall l^* \qquad \left(\mu l^*\right) \qquad (14)$$

[3] There are different denominations for the same concept such as FTR (PJM), TCC (New York ISO), CRR (FERC), etc.

The ISO's objective function is to maximize revenue from selling FTRs to market participants interested in getting congestion hedge. Bid_k is FTR bid submitted by market participants for path *k*, which includes source *i*, sink *j*, and period of time *T*; MW_k is capacity associated with path *k*; Fl^* is power flow on line l^*; $PTDF_{k,l^*}$ is power transfer distribution factor associated with path *k* and line l^*, which represents the percentage of power that flows on line l^* due to transaction *k* (injection in *i* and withdrawal in *j*); and $Fl^{*\max}$ maximum capacity to be auctioned on line l^*.

After solving this optimization problem (12)-(14), FTR prices can be computed. There are two equivalent ways of obtaining FTR prices ρ_k, either forming the Lagrangian function and getting first derivative with respect to decision variable and equaling it to zero; or changing $PTDF_{k,l^*}$ for $\left(A_{i,l^*} - A_{j,l^*}\right)$ first, and then repeating the previous process. The second alternative has the advantage of obtaining congestion components of LMPs $\rho_i^{'}$ for all buses in the system, which simplifies calculation of any potential FTR price.

$$\rho_k = \sum_{l^*} \mu l^* \left(- PTDF_{k,l^*}\right) = \sum_{l^*} \mu l^* \left(A_{j,l^*} - A_{j,l^*}\right) \qquad (15)$$

$$PTDF_{k,l^*} = A_{i,l^*} - A_{j,l^*} \qquad (16)$$

$$\rho_i^{'} = \sum_{l^*} \mu l^* A_{i,l^*} \qquad (17)$$

$$\rho_k = \rho_j^{'} - \rho_i^{'} = \sum_{l^*} \mu l^* \left(A_{j,l^*} - A_{i,l^*}\right) \qquad (18)$$

It is important to remark that before each FTR auction; ISOs contact Transmission Owners (TO) about possible transmission outages that may affect transfer capability for major corridors and interfaces. Finally and after performing transfer analysis, decide about the capacity that will be auctioned $Fl^{*\max}$, and the network topology that better reflects the future reality A_{i,l^*}.

V Numerical examples

In order to clarify some concepts, an academic numerical example is presented (Fig. 1).

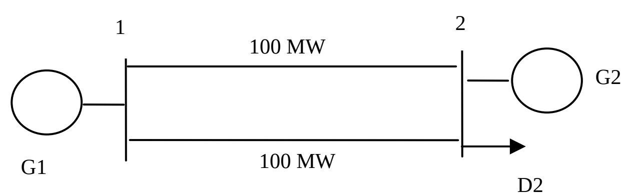

Fig. 1: Two-bus power system example.

Generator G1 has the following characteristics: MC1 = 30 $/MWh, Pmin = 0 MW, Pmax = 300 MW.

Generator G2 has the following characteristics: MC2 = 50 $/MWh, Pmin = 0 MW, Pmax = 400 MW.

Load D2 is an inelastic demand, 210 MW.

The ISO after communicating with TO and analyzing its system decide to auction 200 MW of transmission rights for the following period of time (in this example 1 hour). Following the methodology described in Section IV, different market participants submit bids to ISO who is in charge of the auction. Let us assume that a given third party has the highest bid and gets all the 200 MW rights at 18 $/MWh based on (12)-(14).

FTR holder pays to ISO: 18 $/MWh 200 MW 1h = $ 3,600; and has the right associated with 200 MW of FTR from bus 1 to bus 2 for the following delivery time.

ISO collects the FTR auction revenue and pays to TO for selling 200 MW of transmission rights: 18 $/MWh 200 MW 1h = $ 3,600.

During delivery time, ISO collects payment from load serving entities for power consumed, and pays generators for power produced. The connection between them is the LMP computed as shown in Section II.

Then, two scenarios are analyzed.

a) Normal condition
Under normal condition, both lines are in operation permitting to flow 200 MW from bus 1 to bus 2. After solving optimization problem (1)-(4), we obtain:

Pg1 = 200 MW, LMP1 = 30 $/MWh; Pg2 = 10 MW, Pd2 = 210 MW, LMP2 = 50 $/MWh.

The difference between payments, defined as merchandising surplus (MS), is used by ISO to pay FTR holders.

MS = 30 $/MWh (-200 MW) 1 h + 50 $/MWh (210 MW – 10 MW) 1 h = $ 4,000.

Therefore, ISO collects an extra $ 4,000.

FTR debt = 200 MW (50 $/MWh – 30 $/MWh) 1 h = $ 4,000.

Therefore, in this case MS collected by ISO is exactly the amount necessary to pay FTR holder ($ 4,000 = $ 4,000).

Remark: this matching happens independently of the price paid in the FTR auction for the given path.

b) Outage condition
In this scenario, only one line is in operation, permitting to flow only 100 MW from bus 1 to bus 2.

Pg1 = 100 MW, LMP1 = 30 $/MWh; Pg2 = 110 MW, Pd2 = 210 MW, LMP2 = 50 $/MWh.

MS = 30 $/MWh (-100 MW) 1 h + 50 $/MWh (210 MW – 110 MW) 1 h = $ 2,000.

Therefore, ISO collects an extra $ 2,000.

FTR debt = 200 MW (50 $/MWh – 30 $/MWh) 1 h = $ 4,000.

Therefore, in this case MS collected by ISO is not enough to pay 100 % to FTR holder ($ 2,000 < $ 4,000).

Remark: Even though congestion level and LMPs are equal for both cases, in scenario b) MS was not enough to pay the FTR contract completely. This revenue inadequacy happens because in the FTR auction 200 MW was sold/allocated but during delivery time it was possible to deliver only 100 MW.

VI Discussions

As we have shown in previous examples, it is very important to estimate $Fl^{*\max}$ as close as possible to $Fl^{\max}$. Major discrepancies between MS and revenue needed to honor FTR holders have been observed in the market due to this problem. It is important to understand that there are two major group of players involved in this issue, one that takes active role and other a passive one.

One group is composed by day ahead/real time market participants who have exposures to congestion and try to mitigate those buying FTRs. Speculators, as well, participate in this process trying to arbitrage short-term opportunities improving liquidity and efficiency. These market players have clear financial exposures and interests.

The other one are ISOs and TOs, which in general are non-profit organizations or operate under guaranteed rate or return structure. Both do not take major financial risks in this process.

ISOs are non-profit organizations that do not necessarily receive better payment for better service. TOs get paid from revenue collected from FTR auctions; the incentive here is to sell as much capacity as possible but not necessarily the same as the finally delivered.

We have already observed in the market, events when rescheduling major transmission line outages have created significant revenue inadequacy, but TOs and ISOs who play a major role in the process, were financially immune. Other times, rescheduling transmission outages after the FTR auction, moving them from one month to other, or from week days to weekends, have made FTR positions totally worthless. Obviously, FTR holders took the complete loss without financial recognition from ISOs/TOs.

In situations like these, we are dealing not only with price uncertainty but also with lack of efficiency/incentives that create major un-hedgable exposures to critical market participants. In addition to that, they create non-systematic and random redistribution of risk.

It is imperative to close this open link between responsibility for risk creation and financially exposed participants. A possible alternative is promoting mechanisms for creation of for-profit System Operators, and/or for-profit Transmission Organizations that get compensated according to service and performance. Performance Based Regulation, instead of Rate of Return Regulation, may be an interesting alternative to analyze.

More research in this direction, linking financial risk and financial opportunities, in a more dynamic power industry is highly desired and encouraged.

VII References

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VIII Biography

José Arce is Manager of Power Analytics in the Optimization & Trading Strategy Department at Edison Mission Marketing & Trading, Boston MA, USA. He obtained his Ph.D. in Electrical Engineering from IEE, National University of San Juan, Argentina, in 2001. He was Visiting Student at the MIT Energy Laboratory in 2000, and Postdoctoral Associate at the MIT Laboratory for Energy and the Environment in 2001, Massachusetts Institute of Technology, Cambridge MA, USA. His main interest is in the areas of energy economics, trading, optimization and risk management.

Scott Wilson is Director of Optimization and Trading Strategy for Edison Mission Marketing and Trading. He has been involved in the energy business over 15 years. During this period, he has managed physical and financial trading portfolios in petroleum and electricity markets. He has also managed fundamental and technical analytic departments at numerous trade and investment houses. Mr. Wilson enjoys the challenge of fundamentally valuing the energy markets and the specific economic relationships between them.