Improving Market Participant Strategies with FTR Options

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Abstract: Strategies that reduce risk and maximize profit are of great interest to electricity market participants. Commodities and financial instruments that can be hedged to reduce uncertainty and manage risk are important components of such a strategy. One such vehicle is the fixed transmission right (FTR). The holder of an FTR is entitled to the transmission congestion rents collected between specified points of delivery and receipt. However, if congestion occurs in an unanticipated direction, the holder of an FTR is obligated to pay. An interesting compromise derivative [1,2] is the FTR option (FTRO). The FTRO gives its holder the right to the congestion rents if they are positive, without the obligation to pay if they are negative. In this paper the authors provide examples of how FTR options can be utilized as part of a comprehensive market strategy. Profitability with and without the FTRO is determined under various market and network scenarios. Methods and assumptions required for valuing the options are examined, including equations similar to Black-Scholes.

Keywords: FTR, decision analysis, options pricing, risk management, power system deregulation, congestion management.

I. INTRODUCTION

Regulations governing electricity markets around the world are being re-designed to promote competition [3,4,5]. In addition to the removal of entry barriers for new market participants, formerly monopolistic utilities have been forced to separate their generation, transmission, and distribution into independent companies known as GENCOs, TRANSCOs, and DISTCOs, respectively. In this environment, new market entities are emerging (e.g., energy service companies (ESCOs) that purchase wholesale electricity and repackage it for resale to the end-consumer). Most of these market participants are profit-based and seek profitable bidding and operational strategies.

The strategies depend upon the market rules for which they are designed, and the market rules vary from region to region. In some markets, organized exchanges offer a convenient centralized location for trading electricity products and develop locational marginal prices (LMPs) [6]. The exchanges may promote liquidity by becoming an intermediate partner to all multilateral trades removing traders' uncertainty that their contract partner may default. The power exchanges interface with an independent system operator (ISO), responsible for maintaining a secure electricity network. Other market regions rely on decentralized trading taking place bilaterally. Strategies for bidding and operating physical assets in under bilateral trading may vary widely from those used for centrally allocated markets.

Properly designed electricity markets should promote economic efficiency and secure power system operation. This means balancing the simplifying assumptions required for creating a liquid market with the reality of power system operation. Power flows through a network according to the laws of physics (i.e., Kirchoff's laws), making it difficult to predict how a particular transaction might impact the network without considering all other transactions. Additional complexity comes with the market treatment of supportive services (e.g., reactive power and transmission) related to the physical flow of electricity, which may vary widely with the market implementation.

In many markets, equilibrium prices are largely impacted by transmission congestion. Transmission congestion can prevent the transport of resources at one location (e.g., node, zone, hub) of the network to the location where it is needed. This causes the price of electricity at the demanding end to rise, and the price at the sending end to fall. Commonly the cost of congestion is measured by the differences in LMPs. This cost is collected from those transporting electricity across the congested path providing an incentive to shift generation to the other side of the congested transmission path.

The uncertainty of delivering power without knowing which transmission lines will be congested has led to the creation of financial or fixed transmission rights (FTRs). Interested participants can purchase FTRs from an injection point to a delivery point. While it cannot guarantee physical delivery, the FTR makes the holder financially whole by entitling the holder to congestion rents collected along that path in that direction. If network congestion requires a supplier to pay large collection rents to deliver the product, the FTR allows that supplier to offset the charges. Unfortunately if other transactions on the network cause the power to flow in the opposite direction (counter-flows), the FTR holder is obligated to pay the negative congestion rent.

Many market participants have expressed an interest FTR options. An option on an FTR would allow the holder to collect the congestion rents when they were positive, but not obligate them to pay negative congestion rents. Several markets regions are on the verge of adopting FTR options. Several more markets are considering the sale of Flow Gate Rights, which share the non-obligatory nature of FTR options. If available, the FTR option should be considered a potentially valuable part of a market participant's strategy.

The remainder of this paper is organized as follows. Section II provides a simple example of how FTRs as an obligation are used to hedge against congestion, and the downside risks associated with the obligation. Section III presents the basics of FTR options, how they can be valued, how they can be utilized by the participant, and contrasts them with the FTR obligation. Section IV compares participant profitability using FTRs with that of FTR Options on a sample system. Optimal portfolio ratios of FTR and FTR Option ratios are discussed. Finally, Section V presents summaries and conclusions.

II. FTR

A. Description

FTRs are an important means of mitigating market participant risk. Generally allocated in periodic (e.g., monthly, annual) auctions, FTRs allow their holder to hedge against uncertainties in LMPs that may be caused by congestion. While an FTR cannot guarantee physical delivery of power, the FTR does entitle the holder to the congestion rents collected from a specified injection point to a specified delivery point for a specified time. These rents might give the supplier the choice to purchase power at the delivery point from market when congestion prevents transmission.

B. An example

To illustrate how an FTR is utilized, an example with and without an FTR is presented. Losses are ignored in this example. Suppose that generator *G* is able to generate electricity for a cost of $10/MWhr. G wants to lock-in a price for generation and has bilaterally contracted to supply 100 MW for an hour to load *L* for $12.50/MWhr. G (node A) and L (node B) are connected through a meshed network as shown in Figure 1. If the network is not congested and LMPs at nodes A and B are $10/MWhr, then G generates the 100 MWs, and L consumes 100 MWs. G collects $250 more from the bilateral contract that it would have collected from selling to the spot market. L paid $250 more than it would have paid from the spot market. Even though in this scenario G profited $250 and L “lost” $250, both G and L are happy because they locked in their price ahead of time reducing their exposure to the uncertainty of the energy spot price.

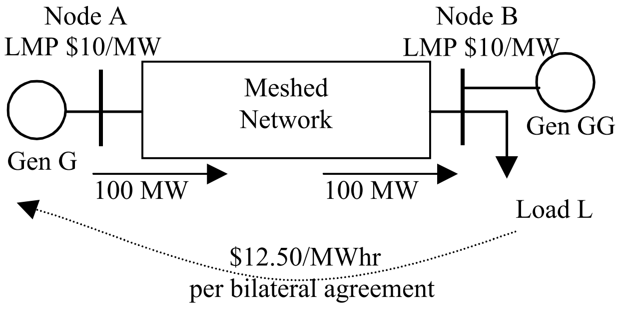

Figure 1. Simplified network, without congestion.

However, if the network between Node A and Node B is congested as shown in Figure 2, the LMPs at both of the nodes will be different. G may not be able to physically deliver its generation, and may have to purchase generation at node B to meet its obligation to L. Because generation at node B could be quite expensive, G is now exposed to considerable risk.

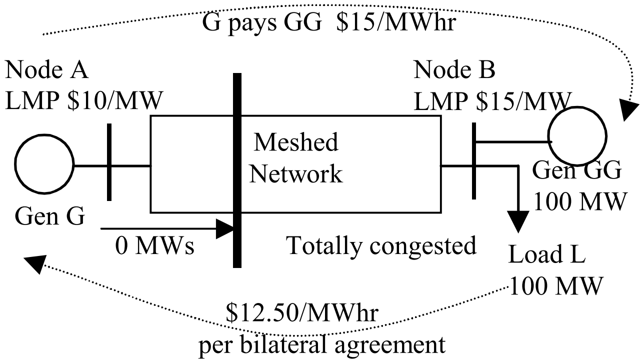

Figure 2. Simplified network with congestion (decentralized dispatch).

An example will help illustrate this exposure to price uncertainty. If the path from A to B was completely congested as shown in the figure, and LMP at B was $15/MWHr, then G would be forced to purchase power at a higher LMP at B (e.g., $15/MWHr) and deliver it to L who would pay only $12.50/MWHr. This means that G would be losing $2.50/MWHr. If LMP at B was lower than at A, then congestion is in the opposite direction and G will generate from its own unit. Note that in a less congested scenario, G may be able to provide some power from its own generator and would purchase the remainder from GG. Table 1 shows G’s profit in a decentralized environment for the bilateral transaction with L under scenarios with varying LMPs at node B. In the table, G’s profit is calculated as:

$$profit := revenue - total\ costs$$

where,

revenue := L’s payment to G
totalcost := (G’s gen cost)+ (G’s payment to GG)
G’s gen cost := ($10/MWhr)* (G’s gen)
G’s payment to GG := (LMP@B) * (GG MWs)

Table 1. G’s profit for 1-hr 100 MW bilateral contract under 4 scenarios.

LMP A **$/MWHr**	**LMP B** **$/MWhr**	**L Pays G** **$**	**G gens** **MW**	**G’s gen.** **$**	**G pays GG** **$**	**G’s total Cost** **$**	**G’s “profit”** **$**
10	20	1250	0	0	2000	2000	-750
10	15	1250	0	0	1500	1500	-250
10	10	1250	100	1000	0	1000	250
10	5	1250	100	1000	0	1000	250

In a centrally dispatched market, the amount scheduled at each generator is determined by the independent system operator (ISO), which is essentially running a powerflow that considers physical network limits, bids and offers. The LMPs are a result of the central dispatch and allocation process. The ISO generally would not necessarily know about and therefore would not consider any bilateral agreements between G and L in the centralized dispatch. The ISO would collect and distribute the money associated with the centrally allocated transaction. Table 2 demonstrates results for the same size transaction and the same nodal price scenarios when coordinated by the ISO.

Table 2. Settlement for G to L 1-hour 100 MW Transaction under ISO.

LMP A $/mwhr	LMP B $/mwhr	L Pays ISO $	G Gens mw	ISO pays G $	ISO pays GG $	G pays L $	G cost $	G's Profit $
10	20	2000	0	0	2000	750	750	-750
10	15	1500	0	0	1500	250	250	-250
10	10	1000	100	1000	0	-250	1250	250
10	5	500	100	500	0	-500	1000	250

Table 3 demonstrates generation and payments allocation in the presence of congestion induced transmission limits. The ISO is clearing (or not clearing) offers submitted by generator G at node A (100 MW offer @ $10/MWhr) and by generator GG at node B (100 MW @ $15/MWhr). Load L requires 100 MW in this example. The table illustrates generation levels and settlement under different levels of congestion limited transmission. When LMP A is greater than LMP B, G is not responsible for any congestion payments (CP). When the LMPs at all nodes are the same, there is no congestion in the network. However when the LMP A is less than LMP B, G is liable for congestion payments (implicitly defined in the previous table) [(LMP B-LMP A)*MW] as it has not hedged against this congestion.

Table 3. Effects of congestion on G's profit without FTR

Cong. Limit A-B MW	Supply Cleared @ G MW	LMP @ A $/mwhr	Supply Cleared @ GG MW	LMP @ B $/mwhr	L Pays ISO $	ISO Pays GG $	ISO Pays G $	G pays ISO CP $	G's Profit $
100	100	10	0	10	1000	0	1000	0	250.0
75	75	10	25	15	1500	375	750	375	125.0
50	50	10	50	15	1500	750	500	250	0.0

To hedge against paying the uncertain LMP at B under congestion, G can chose to purchase an FTR of 100 MW (in this example, the price is assumed to be $1/MW) to ensure that it is hedged. G's profit (including cost of purchasing FTR and profit of selling electricity at $2.50 more than generation costs) is shown in Table 4. LMP A is kept the same while LMP B is reduced from $15 to $5. Congestion limit is assumed to be 100 MW

Table 4. G's Profit with an FTR

LMP @ A $/MWhr	LMP @ B $/MWhr	FTR MW	FTR $/MWHr	G pays ISO CP $	ISO pays G CR $	G's Profit $
10	15	100	1.0	500	500	150
10	10	100	1.0	0	0	150
10	5	100	1.0	500	0	-350

When LMP B is greater than LMP A, G has a profit of $150, as it collects $500 in congestion rent and has paid $100 to purchase the FTR and has a profit of $250 for the bilateral contract with L. When there is no congestion, then it also stands to make a profit of $150. However when LMP B is greater than LMP A, then G stands to loose $350 due to the counter flow in the opposite direction of the purchased FTR. Hence as the price differential increases, and the LMP A is larger, then G would start to make large losses although it has purchased an FTR and hedged against congestion. G is always financially liable for any congestion charges due to counter flow in the opposite direction of the FTR purchased.

C. *Problems and limitations*

While FTRs can be used to mitigate risk, they come with a risk of their own. If power flows in an unanticipated direction (counter-flows), the FTR holder is obligated to pay the negative congestion rent.

III. FTRO

A. *Description*

An FTRO is a form of insurance that gives its holder the right to the congestion rents when power flow is in the indicated direction, without the obligation to pay when unanticipated power flow means that the rent is would be negative. A party "writes" an FTRO in return for the premium, or FTR option purchase price, and is then obligated to collect/pay congestion rents when the flow is opposite the direction anticipated.

Figure 3 shows the profitability of an FTRO to the congestion rents from point A to B. The purchaser has paid a premium (e.g., $1) to the FTRO writer giving the purchaser the right to positive congestion rents (e.g., $0). The purchaser has reduced risk by limiting losses to the premium. On the right side of the figure is shown what happens from the FTRO writer's point-of-view. The FTRO writer receives the premium for assuming the risk and is obligated to pay the congestion rents when they are negative.

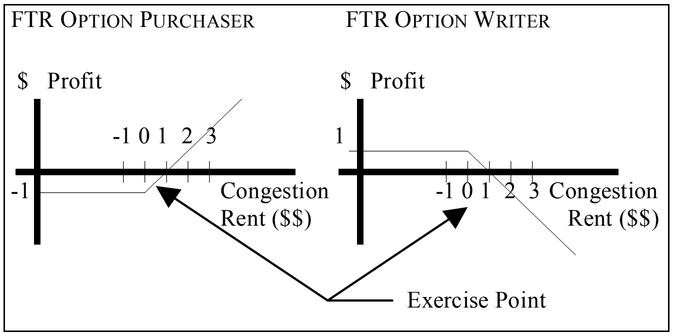

Figure 3. FTRO profitability

B. *Pricing and valuation*

The FTRO price should reflect the value of the FTRO to the potential holders. The worth of an FTRO may vary from trader to trader due to risk preferences, makeup of portfolios (collection of assets and contracts), etc., but is largely dependent on the uncertainty in the underlying asset. Large uncertainties in the direction of flow on the FTR path and in the amount of congestion rent to be collected translate to high premiums (FTRO prices).

While the Black-Scholes equation has been used in many markets to value options, it's usage assumes many things about the traded physical commodity that may not be true about electricity. Electricity is non-storable. Futhermore, experience is limited as it has not been traded as a homogeneous commodity long enough to establish predictable prices and reliable volatility information. Black-Scholes requires:

- known and constant short-term interest rates
- no dividends
- efficiently priced underlying assets
- European options
- No transaction costs (for buying and selling)
- Can borrow any fraction of underlying asset value
- No artificial restrictions on, or penalties for short selling

The Black-Scholes equation for valuing a put option for traditional commodities is as follows:

$$p = \left[X \cdot \exp\left(-r \cdot (T-t)\right) \cdot N(-d2) - S \cdot N(-d1)\right]$$

where:

$X = strike \cdot price$

$S = spot \cdot price$

$r = risk \cdot free \cdot rate$

$N(dn) = Cumulative \cdot Normal \cdot Distribution$

$T = \exp iration \cdot date$

$t = current \cdot time$

$$d1 = \frac{\ln\left(\frac{S}{X}\right) + \left(r + \frac{\sigma^2}{2}\right) \cdot (T-t)}{\sigma \cdot \sqrt{T-t}}$$

$$d2 = d1 - \sigma \cdot \sqrt{T-t}$$

The method used to value options must consider the idiosyncrasies of electricity. Many permutations of Black-Scholes have emerged. Another approach that can help identify an upper bound on the value of the FTRO is to determine expected monetary value (EMV) and value at risk (VAR) under scenarios of interest (see Figure 3).

C. *Valuing FTRO with Decision Analysis*

Decision Analysis can be viewed as a methodology for making decisions with uncertain outcomes. Comprehensive treatments can be found in many volumes [7, 8]. Note that the decision analysis method is not a competitor to the other modeling methodologies. Rather, it is complementary in that it integrates the results of various models and applies them to decision making. Reference [9] and [10] describe the application of decision analysis to bulk-power marketing problem.

The comparison of FTR with FTRO is difficult to model due to risk and uncertainties associated with the fluctuating market demands and consequently the changing transmission congestion patterns. In view of these uncertainties, the comparison problem is a stochastic optimization problem. The DA approach converts the stochastic optimization problem into a set of deterministic optimization sub-problems by developing decision tree as shown in Figure 4.

The square and oval nodes represent decision and chance nodes respectively. A path of decision tree represents a sequence of decisions after the corresponding probable events are resolved. Thus, each path of the decision tree has cost associated with the solution of deterministic problem. The solution of all the deterministic sub-problems are then combined to obtain the solution of the original problem. In Figure 4, nodes are depicted as follows:

Node A	Decision to Buy Monthly FTRO
Node B	Decision to Buy Monthly FTR
Node C	Chance (probability) of Price at Point of Delivery (POD)
Node D	Chance (probability) of Price at Point of Receipt (POR)

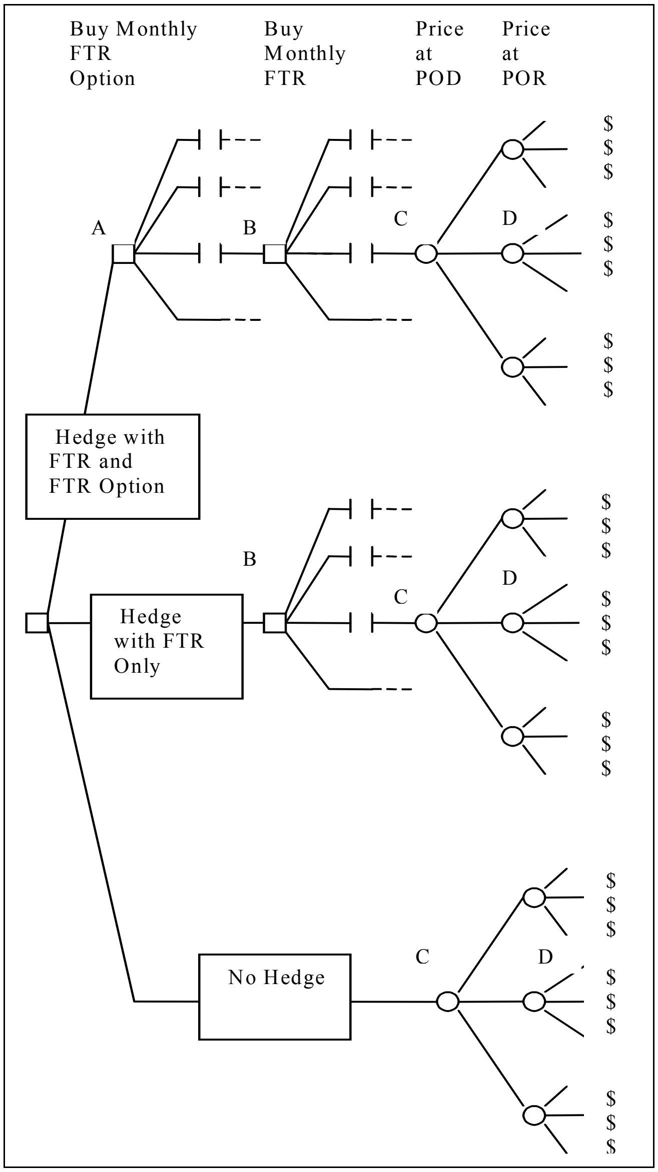

Figure 4. Decision Analysis Model of FTR/FTRO strategy

Each path following the node A represents a purchase of Monthly FTRO of a fixed MW at a certain premium charged by the financial company. The payment towards purchase is usually called pay toll in the decision analysis terminology. Similarly, each path following the node B represents a purchase of Monthly FTR of a fixed MW at certain cost. The paths following the node C and node D represent market prices for energy at POD and POR respectively with different probability.

The expected prices at the POD and POR are determined through contingency analyses and forecasts of price and demand for the most probable scenarios. It can be argued that those scenarios having a low probability of occurrence (below some threshold), and having minimal value at risk can be removed from consideration.

The pricing of a given FTR option is computed as follows:

FTR Option price = Expected Value of payment for Hedge with FTR and FTRO
- Expected Value of payment for Hedge with FTR only.

Furthermore, the value of premium structure of a FTRO can also be evaluated using this framework. Sensitivity analysis can be used to compute the effect of price volatility on a given decision.

IV. COMPARISON OF FTR WITH FTRO

The FTRO is an additional tool for managing risk. Here the FTR only example is augmented with FTRO for comparison. Revisiting the simple system depicted in Figure 1, Table 5 provides an example of hedging with FTRO. The FTRO protects G from congestion charges due to counter flows. The profit of G if it purchases an FTRO from Node A to Node B is shown in Table 5. Congestion limit is assumed to be 100 MW

From Table 5, when LMP A is greater than LMP B, then G's profit is $100, which is the profit of selling electricity to L minus the cost of purchasing the FTRO. This is also the case when there is no congestion, and when LMP A is greater than LMP B. Hence with an FTRO, G is not responsible for any counter flow from Node B to Node A.

Table 5. G's Profit with an FTRO

LMP A $	**LMP B $**	**FTRO MW**	**FTRO $/MWHr**	**G pays to ISO CP $**	**G gets From ISO CR $**	**G's Profit $**
10	15	100	1.5	500	500	100
10	10	100	1.5	0	0	100
10	5	100	1.5	0	0	100

G may also decide that to use both an FTR and FTRO from Node A to Node B to hedge its financial risks as shown in Table 6. Here G has purchased an FTR of 50 MW @ $1/MWHr and an FTRO of 50 MW @ $1.5/MWHr respectively.

Table 6. G's Profit with an FTR and FTRO

LMP A $	**LMP B $**	**FTR MW**	**FTR $/MWHr**	**FTRO MW**	**FTRO $/MWHr**	**G pays ISO CP $**	**G gets ISO CR $**	**G's Profit $**
10	15	50	1.0	50	1.5	500	500	125.0
10	10	50	1.0	50	1.5	0	0	125.0
10	5	50	1.0	50	1.5	250	0	-125.0

Comparing Table 5 and Table 6, it may be noted that with both an FTR and FTRO, G is able to better hedge its risks. The profit of the ISO over the period of year can be determined by applying various probabilities to the occurrence of LMPs given in both tables. Depending on these probabilities, G may choose to use either one or both of these hedging mechanisms. For example, if LMP A > LMP B occurs frequently over the year, then G may be financially better off to hedge only an FTRO and not both an FTR and FTRO.

V. SUMMARY AND CONCLUSIONS

The use of electricity derivative instruments is an essential instrument that enables market participants to manage risk in the deregulated electricity industry. This work has proposed a framework as well as methodology to mitigate the risk associated in transmission right contracts in the deregulated industry. This paper has presented the concept of FTR Options (FTRO) as a new product to achieve this aim.

The proposed framework can be applied to forward as well as future markets. One of the biggest challenges in operational implementation of the presented model includes prediction of spot market prices. However, the model is well structured such that sensitivity analysis techniques can be readily applied to determine the effect of price shifts on the optimal decision.

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VII. BIOGRAPHIES

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Jayant Kumar received his MS (1993) and PhD (1996) degrees in Power Systems from Iowa State University. He has over ten years of experience in the electric power industry. Prior to joining Alstom ESCA as the manager of market participant applications, he worked at PG&E Energy Services, where he developed software for retail access, designed and developed trading and other applications for PG&E's ESP operation applications. Other experience includes transmission constrained scheduling and location pricing package as well as design and development of applications for New York Power Pool and the California ISO Market.