Financial Transmission Rights, Revenue Adequacy and Multi-Settlement Electricity Markets

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Introduction

Financial transmission rights are essential ingredients of efficient markets in wholesale electricity systems operating under the principles of open access and non-discrimination. A central feature is the revenue adequacy of financial transmission rights to provide full funding and the associated transmission hedges that link transactions between different locations. As summarized in the submission of FirstEnergy Solutions Corp. and others, in their filings under FERC Docket EL13-47-000, a recent pattern in PJM of persistent underfunding of financial transmission rights has raised questions about the nature of the rights, the causes of underfunding, and proposed solutions to restore the viability of financial transmission rights. The purpose of the present comments is to reinforce the other analyses with attention to the basic elements of revenue adequacy in a multi-settlement system. Although perfect revenue adequacy can never be guaranteed, full funding of financial transmission rights is both a good and attainable policy as demonstrated by the implementation under the New York Independent System Operator.

Financial Transmission Rights

Physical rights to use the capacity of the transmission grid would be unworkable as a means to support energy transactions in a competitive wholesale electricity market. The electricity industry struggled for decades in attempts to devise such physical rights under the rubric of the contract path. But in an integrated grid, complex interactions across all generation and load make such physical rights an insurmountable barrier to an efficient market. The solution to the problem of efficient market design is to utilize a system operator under the framework of bid-based, security-constrained, economic dispatch with locational prices and financial transmission rights (FTRs)[1]. The bids and offers express the preferences of market participants. Economic dispatch implemented by the system operator solves the problem of coordination across the grid. The locational prices reflect the marginal value of energy at each location. The difference in the prices defines the opportunity cost of transmission between locations. The FTRs provide the replacement for physical rights through the hedge of this locational difference in prices. (Hogan, 1992)

In the early days of the development of efficient electricity markets is was clear that this basic model would work both in theory and in practice. Eventually, through hard experience, we learned that this approach is the only way to organize an efficient electricity market that honors the principles of open

[1] The generic financial transmission right (FTR) appears under many names, such as transmission congestion contract (TCC), congestion revenue right (CRR), up-to-congestion offers (UTC), auction revenue right (ARR), and so on. The functional equivalent of FTRs, ARRs are an initial regulated allocation to transmission owners or load serving entities to be redeemed in the FTR auction. Essentially all other FTRs are voluntary purchases formal auctions or implicit in forward dispatch and settlements.

access and non-discrimination. (Hogan, 2002) (Hogan, 2010) This approach is now “the textbook ideal that should be the target for policy makers.” (IEA, 2007, p. 16) All the organized markets in the United States adhere to the central elements of this market design.

The FTR is integral to this market design. For the present discussion, ignore losses and focus in the treatment of transmission congestion. When the transmission system is constrained, the locational prices will reflect the difference in congestion costs. A transaction that moves power between two locations will be charged at the difference of the locational prices. This difference can be quite volatile, but charging this cost is essential in maintaining the integrity of the market design. The FTR allows the holder to receive the difference in the locational congestion costs. Hence, if the transactions match, the economic result is the same as having a physical right in that the transaction occurs with no net payment for congestion. In effect, the FTR operates as a perfectly tradable physical right. (Harvey, Hogan, & Pope, 1997)

The advantages of this market design and the role of FTRs have been explained many times and in many places. In the context of the FirstEnergy Solutions filings under FERC Docket EL13-47-000, an especially lucid and useful description appears in the affidavit by Robert Stoddard. (Stoddard, 2013) Suffice it to say that FTRs are a necessary part of the market design, and the market design is the only way to achieve the objectives of open access and non-discrimination for wholesale competitive markets. And the design includes full funding of the FTRs.

Revenue Adequacy

A central feature of the FTR model is the principle of revenue adequacy. The basic definition is that the system is revenue adequate if the revenues collected from the economic dispatch in the form of congestion payments are sufficient to fully fund payments for the FTRs. The general result is that under reasonable conditions, there is a straightforward test that ensures revenue adequacy. If for the given grid configuration, the FTRs would be simultaneously feasible, then no matter what the pattern of actual loads and generation, economic dispatch with locational prices would be revenue adequate. The underlying logic is that the economic dispatch is by definition feasible, and must be at least as valuable as any other feasible solution. In particular, the economic dispatch must be at least as valuable as the FTR implied feasible dispatch, valued at the locational prices. Hence, there must be enough economic surplus value to in effect buy out all the FTRs and reconfigure the pattern of flows according to the economic dispatch. (Harvey et al., 1997)

This revenue adequacy result stands in sharp contrast with the inherent problem of physical rights. The central problem of physical rights was that they could not be guaranteed. A “right” to move power between locations would always be limited by the fact that actual load and generation conditions in real time might preclude the exercise of the right. Hence, it was not possible to award physical rights that ensured that the holder would be able to move the power or capture the economic value. The fully funded FTR does guarantee that the holder will capture the economic value to hedge transactions that either actually move the power, as through a physical right, or provide the power through redispatch as part of the efficient economic solution.

Hence, with the same grid and simultaneous feasibility of the FTRs, the efficient market design provides what is needed for competitive wholesale electricity markets. Even under these idealized conditions, the alternative vision of workable physical rights was a hopeless illusion. Physical rights would not work under the best of conditions. The solution is to provide and fund FTRs.

Of course, the real conditions are seldom ideal. The revenue adequacy condition may not hold in practice. Since the revenue adequacy result is a theorem, this means that real conditions must violate at least one of the assumptions of the analysis. There are many ways to deviate from the ideal, but the most prominent is the problem of ensuring simultaneous feasibility. In essence, the problem arises when we award FTRs for more capacity on the grid than actually exists at the time of the economic dispatch. It is obvious that this could be a problem, and none would expect otherwise. The difficulty could arise from a number of conditions.

First, the grid changes over time. For example, an unexpected transmission outage for an extended period may mean that FTRs, including ARRs, awarded in good faith are no longer feasible during the period of the outage. The result could be revenue inadequacy resulting from a straightforward reduction in capacity.

A second problem is that the revenue adequacy result applies to a complete system. But actual regional transmission organizations cover only a part of the interconnected grid. The result is that power flows across loops through the RTO from generation outside the region serving load outside the region. If the flows could be charged at the difference in locational prices, there might not be a problem. But charging for loop flow is difficult and controversial. To the extent that loop flow has not been accounted for in the allocation of FTRs, the result in any dispatch could be revenue inadequacy.

A third possible problem would be in treatment of other costs that are not related to FTRs, such as for losses, ancillary services or uplift payments that might get lumped in with congestion costs. These are not congestion costs, and would make it impossible to fully fund FTRs if the costs were included with congestion costs.

Before addressing policy for revenue inadequacy, a separate additional point is to emphasize that the congestion costs, fully funded FTRs and revenue adequacy results apply to a particular economic dispatch. When there is more than one dispatch, and more than one settlement, a little care in the accounting is all that is required.

Multi-Settlement Systems

The usual discussion of the bid-based, security-constrained, economic dispatch with locational prices and financial transmission rights builds on an analysis of the real-time market. The FTRs are awarded in advance and are longer term rights. The actual dispatch in real-time produces the real power flows and the associated locational prices. All energy transactions settle at these locational prices, and the real-time congestion surplus funds the FTRs. This is the single settlement system.

In most organized electricity markets, the model extends to include one or more additional dispatch and settlement events. For the sake of the present discussion, consider the introduction of a day-ahead market. The principles would extend to any additional number of settlements. Again, the FTRs have been awarded in advance and are simultaneously feasible for the grid that will apply in real-time. Furthermore, the description of the day-ahead market includes the grid conditions that will apply in real-time. The bids and offers day-ahead are used to determine an economic dispatch.[2] This day-ahead economic dispatch will include locational prices. These prices would be used to settle the FTRs and the day-ahead settlement would be revenue adequate.

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[2] The day-ahead market may include added complexity to deal with multiple hours, start-up and ramping conditions and so on. These are important in the market but not central to the discussion of revenue adequacy.

In effect, the day-ahead settlement and economic dispatch purchase all the longer term FTRs and reconfigure the use of the grid to match the resulting day-ahead schedules. These schedules could be viewed as producing both a pattern of load and dispatch, along with an entirely new set of one-day FTRs. These day-ahead schedules and implicit one-day FTRs would be short-term financial contracts. In real-time, the relevant bids and offers would be incorporated in the real-time with changed generation and load, but the same grid, to determine a second economic dispatch and real-time prices. The day-ahead contracts and the implicit one-day FTRs would settle at the real-time prices. Under our assumptions, the real-time economic dispatch would be revenue adequate.

This sequence of economic dispatches has a clear accounting discipline. (Harvey et al., 1997, pp. 51-52) the day-ahead prices determine the day-ahead settlements, including for FTRs. The real-time prices determine the real-time settlements for the schedules from the day-ahead economic dispatch. To be sure, expectations about real-time prices will affect day-ahead prices. But there is no mixing in the accounting. If the FTRs would be feasible for the grid configuration in the day-ahead model, then the FTRs can be fully funded and the day-ahead economic dispatch will be revenue adequate. Likewise, if the schedules from the day-ahead dispatch would be feasible with the real-time description of the grid, then the real-time economic dispatch would be revenue adequate.

As described in the affidavit prepared by Roy Shanker in conjunction with the FirstEnergy Solutions filing in FERC Docket EL13-47-000, the evolution of the rules in PJM did not adhere to this accounting discipline. (Shanker, 2013) There is a degree of mixing and matching of payments in real-time and those in the day-ahead. If the effects were small, this might not be much of a problem. But it appears that the effects are anything but small, and it is a problem. The diagnosis of the sources of revenue inadequacy will be important in determining the best way to improve the models and allocations of FTRs and other financial contracts. Apparently, as described by the FirstEnergy Solutions submissions, the recent problem arose in the final real-time settlement. This indicates that the problem may lay in the characterization of the day-ahead model. Fixing this problem would be recommended, but it might only move the recognition of the infeasibility to the day-ahead market. In turn, the forward auctions for FTRs would have to recognize the reduced capacity, and so on all the way back to the model of the initial allocation of FTRs and the revenues flowing to ARRs. Thus we have the questions of how to untangle the accounting, how to improve the models, and how to treat policy for revenue inadequacy.

Revenue Inadequacy Policy

The different sources of revenue inadequacy suggest a number of policies to minimize or eliminate the problem. An easy step is to keep the accounting straight in order to identify the location of any revenue inadequacy. As discussed in the Shanker affidavit (Shanker, 2013) an early priority would be to reduce the chance of infeasibilities in longer term FTR allocation and in the day-ahead dispatch. The fundamental principle is to choose each characterization of the transmission grid so that any solution would also be a feasible solution in the subsequent dispatch. Hence, the description of the grid for the day-ahead market should be as close as possible to the actual grid conditions modeled in real time. Likewise, the description of the grid in any forward FTR allocation or auction should be as close as possible to the description of the grid in the day-ahead market. These descriptions of the grid should include the actual physical condition of the grid and an estimate of any loop flows or other activities that use grid capacity without paying the opportunity cost of transmission. The sequence of feasibility tests to preserve revenue adequacy in each economic dispatch implies that a policy to utilize a description of the grid at all stages that comes as close as possible to describing transmission that will be available capacity in real time should tend to minimize any revenue inadequacy.

A conservative allocation of FTRs to maintain the simultaneous feasibility condition would go a long way to ensure that the economic dispatch is revenue adequate and the FTRs are fully funded. This was the experience in PJM for many years and the problems of underfunding were minimized. Whatever the sources of the current underfunding problem, adherence to the principles of simultaneous feasibility and the required accounting for each separate economic dispatch should help improve the situation.

However, even with a better allocation of FTRs the problem of revenue adequacy could persist at a lower level. This raises the question of how to deal with any revenue inadequacy that remains. The basic principles should be to ensure that the rules do not affect the incentives for efficient economic dispatch, and the efficient solution includes perfect or near perfect funding of the FTRs. The various filings in the FirstEnergy Solutions proceeding suggest a number of options, including adopting the NYISO approach.

In selecting a policy, there should be a distinction between achieving full funding of FTRs and dealing with revenue inadequacy. Revenue adequacy under the simultaneous feasibility test is sufficient to guarantee full funding. But it is possible to maintain full funding even without revenue adequacy. The only question is the policy for where to allocate any funding deficit. Although there are many explicit policy choices available, there is less flexibility in changing the ultimate outcome.

An equilibrium argument implies that a policy of under-funding FTRs would be anticipated in the bids to acquire FTRs in the first instance. Given the regulatory allocation of ARRs, all subsequent acquisition of FTRs is voluntary, and the volunteers won't pay more than the FTRs are worth. The same principle applies all the way along the chain from real time back to the initial allocation of FTRs and the determination of the revenues to award to the holder of ARRs. In aggregate, therefore, the ARRs can't be worth more than the expected aggregate value of the actual congestion. In choosing between allocating the revenue deficit to holders of FTRs (through underfunding) versus allocating any congestion revenue deficit to holders of ARRs (the transmission owners), the equilibrium net revenues received by ARRs may not change much. The principle difference would be the implications for the efficiency impacts of underfunding FTRs.

As summarized above, there are many efficiency benefits of having fully funded FTRs, to support long-term contracts between generation and load, by providing a substitute for the unworkable physical rights model. If FTRs are only a very imperfect hedge because of underfunding, these benefits will not accrue. From the perspective of market design, where the FTR analysis of revenue adequacy is not dealing with market failures that might indicate a need for a general uplift, the dictates of efficient design would point to allocating any congestion revenue deficiency to transmission owners through as beneficiaries of ARRs. In equilibrium, there is no good reason to leave FTRs underfunded.

Under the NYISO protocol, FTRs are fully funded and any revenue adequacy is allocated to the transmission owners that benefit from the sale of auction revenue rights (ARR). These ARRs are an allocation that is based on an attempt to protect and approximate the transmission rights that existed for transmission owners and their loads before inauguration of the competitive market. For all the reasons summarized above for any approach based on physical rights, these ARR allocations can be only an approximation of the physical rights. It is ironic that the physical rights that were declared under the prior regime had the inherent property that they could not be fully guaranteed, in part because the stated rights were not simultaneously feasible, are now protected to seek at least a temporary protection from bearing responsibility for revenue inadequacy. However, in PJM the rule was adopted to modify the initial transmission auctions in order to protect full funding of the ARRs. This policy contributed inevitably to a revenue adequacy problem by awarding more transmission rights than allowed under the simultaneous feasibility test. And as suggested above, this policy is counterproductive in the long run because it dilutes the efficiency benefits of FTRs without providing any equilibrium increase in the revenues for ARRs.

An alternative approach, equivalent to the NYISO procedure, would be to recognize that the initial allocation of ARRs was not simultaneously feasible and impose any revenue deficiencies in the FTR allocation on the transmission owners, the holders of the ARRs[3]. Hence, the initial allocation of ARRs would be as good as possible in approximating the unworkable and incomplete physical rights. The subsequent auction of FTRs would utilize the best approximation available of the anticipated grid conditions. This would make the FTR allocations simultaneously feasible. The FTRs would be fully funded. Any revenue deficiency in the initial auction would be allocated to the transmission owners, who were the beneficiaries of the ARRs. Similarly, any subsequent economic dispatch would fully fund all the resulting schedules and rights, and any revenue deficiency would be allocated to the transmission owners. In the end, the transmission owners would be responsible for the total revenue deficiency arising from the difference in the capacity of the actual grid in real time and the assumed grid in the initial FTR auction. This approach would provide a source of incentive to both maintain the grid capacity and improve the forecast of the grid conditions. It would also ensure that the transmission owners were not, in effect, selling transmission capacity in excess of the actual capacity of the grid. And most importantly, the NYISO approach would guarantee full funding of FTRs in support of the efficient wholesale market design.

Summary

Fully funded financial transmission rights provide the substitute for unworkable physical transmission rights. If the set of financial transmission rights would be simultaneously feasible under the grid configuration for an economic dispatch, then the congestion payments at locational prices would be sufficient to fund the FTRs. This revenue adequacy condition applies separately to each economic dispatch in a multi-settlement system. A good policy is to do as well as possible in modeling the physical grid capacity and awarding FTRs that are likely to be simultaneously feasible in all subsequent dispatches. In the presence of any remaining revenue adequacy, the declaratory policy should be to maintain full funding of FTRs and assign any revenue inadequacy to the beneficiaries of the allocated auction revenue rights, chiefly the transmission owners. In long run equilibrium this policy should not significantly affect the net revenues flowing to the transmission owners, but it should provide the many efficiency benefits that can only be obtained through fully funded financial transmission rights.

[3] In markets such as PJM where ARRs are assigned to load serving entities, this approach could still apply but would without the incentives for improved grid maintenance and accurate forecasts of outages.

Endnote

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