ESAI’s Proposal to Accelerate Merchant AC Transmission Investment

Despite the urgent need for new transmission infrastructure, investment in merchant AC projects has yet to materialize. The industry has been stymied by the conundrum that building a new transmission line erodes the very spread that the line was intended to capture. However, on the basis of FERC’s recent approval of changes to the PJM Tariff, and a New York ISO planned change to its Tariff, ESAI proposes a way to modify FERC’s Standard Market Design (SMD) that would stimulate merchant AC transmission projects.

In 90 percent of the landscape of the United States, transmission siting is a difficult issue. In the other 10 percent, it is an enormously difficult and decisive issue. In that 10 percent, however, the challenge of siting a baseload power generation facility is likely to be equally daunting. The majority of the people in this country live in that 10 percent of the landscape. Thus, the central interest in transmission policy should be — but seldom is — in the 10 percent of the landscape that contains the load pockets of the power markets. The load pockets include most of the major American cities, and so, to a significant degree, transmission policy should focus on how to bring power to the people who live in urban areas.

If transmission is to be more of a normal business and less of a totally regulated one, it makes sense to ask the most fundamental business question: what is the product? In a direct current (DC) project, the product will be a “transmission scheduling right,” which entitles the owner to sell energy, capacity services, and other services from the source market to the sink market. Since DC lines are typically able to carry power both ways, these services can be sold both ways — the sink can become the source.

The product on conventional AC lines is more subtle. Since these lines exist within a network of power lines and are typically not controllable as separate delivery entities, the effect of a new AC line is to increase the transfer capacity between source and sink. As a result, in markets where “locational pricing” exists, the product of a new AC line will be measured as the difference in prices between the source and sink markets.

Under FERC’s proposed SMD, and in current practice in PJM and New York, an investor in expanding the capacity of the transmission system would be granted “congestion revenue rights” (CRRs, FERC’s term), “fixed transmission rights” (FTRs, PJM’s term), or “transmission congestion contracts” (TCCs, New York’s term). Essentially, these are the financial value of the difference (the “spread”) between the prices in the day-ahead markets at the ends of the new transmission line.

The trouble with this formulation is that if the line is built too big, it may well destroy that spread. This is not a problem that is unique to electricity, of course. Any company that overbuilds capacity can find itself in trouble, so part of the solution to this problem is to be sure not to overbuild.
This, in turn, raises a host of other issues. We pursue two of them here. First, the problem with CRRs, FTRs, and TCCs is that they have never been used as the basis for financing a transmission line. Investors today (after a ten-year binge of undiscriminating investment in electricity markets) are understandably wary of putting lots of money (and transmission is usually expensive) in products that are likely to have quite volatile value, and which have significant regulatory risk as a variety of states and interest groups fight FERC’s SMD design.

Second, transmission investments that relieve load pockets demonstrably convey a benefit that is not monetized today. That benefit is an artifice of regulation of power markets that – in our opinion – is likely to endure: the requirement that load-serving entities in load pockets maintain a minimum amount of generation within their service area. Such “locational capacity” requirements are in place in the New York market, and should be in place in New England. They do not exist, however, in PJM.

The RTO and Merchant Transmission

Even though PJM does not [yet] have a locational capacity requirement, PJM’s recent Tariff changes to accommodate merchant transmission do introduce a useful new set of acronyms into the electric lexicon. Specifically, PJM has identified the following rights (and obligations) for those who would invest in the transmission system it has the responsibility for operating. For transmission projects connecting PJM to another control area:

- Transmission Withdrawal Rights (TWRs) — Firm TWRs would allow a generator in PJM to offer capacity services to the control area at the other end of the line, assuming that “PJM firm” would be compliant with the definition of firm in the sink area. Non-firm TWRs would allow a generator in PJM to sell energy (and perhaps some ancillary services) to the sink area.
- Transmission Injection Rights (TIRs) are the mirror image — rights to bring capacity and/or energy services into PJM from another control area.

For AC transmission projects within PJM, the pivotal concept is Incremental Deliverability Rights (IDRs). Essentially, this is the measurement of the increase in the amount of generation that can be injected at a location as a result of an AC transmission project.

So far, so good. But PJM’s changes do little to make AC merchant transmission more attractive. CRRs (FTRs) by themselves are not stimulating any new transmission investment. A more stable revenue flow is needed to do that.

New York: Locational Capacity Requirements and “Capacity Demand Curves”

FERC’s SMD plan notes that RTOs (which it calls ITPs) in some areas may want to take special measures to deal with load pockets. Since FERC’s initial moves to deregulate the power market, there has been a boom in generation development but not in transmission development. Generators typically picked the sites for their plants with an eye towards siting convenience and access to input fuels. Thus, there are many new power plants in rural areas, very few new plants in urban areas. Generators may have believed that, if they built the plant, someone else (the ITP, the LSE) would build transmission to take the power to market.

As a result of the disparity in generation endowment, there are load pockets of varying degrees of pocket depth all over the country. Some are severely isolated, and require enormous investments in transmission to reduce or in some cases just manage their congestion costs.

As noted earlier, New York’s response to the presence of its two “deep load pockets” (New
York City and Long Island) has been to institute a locational capacity requirement. 80 percent of the New York City peak load is supposed to be served by generating capacity electrically or geographically located within the City load pocket. In Long Island, there is a requirement that 93 percent of the Island’s peak load be served by generating capacity located on the Island. “Electrically located” means that a generator located in another jurisdiction but committed to the load pocket via an AC or a DC line also qualifies towards the locational requirement.

Transmission investments can reduce these local requirements. In the case of New York City, for example, a 1996 study by Stone and Webster noted that the “in-city capacity requirement is a function of transmission cable import capability into the City relative to in-City load.” Since the existing AC cable transmission system can only satisfy 50 percent of New York City’s load, the minimum in-city generation requirement has to be 50 percent. Stone and Webster’s study then goes through a logical progression of events that affect the reliability of either the in-city generators of the AC cables into the City to arrive at the view that reliability concerns require that New York City have an 80 percent “locational generation capacity requirement”.

This same logic indicates that, as transmission capacity into the constrained market expands, the locational capacity requirement can be reduced. While New York City has not yet had a merchant transmission project completed, Long Island has, and the new 330 MW DC transmission line from Connecticut to Long Island will reduce the locational requirement in that market from 93 to 87 percent¹.

A “Locational Capacity Reduction Payment Right”

That reduction has real value for the load serving entity. The Board of the New York ISO recently agreed to constitute (subject to FERC approval) a “capacity demand curve.” This entails a payment schedule by LSE’s to generation, the size of which depends on the overall adequacy of generation in relation to requirements. If implemented, it would prevent capacity payments from “falling off the cliff” during periods of surplus in exchange for preventing them from “going to the moon” in periods of deficit.

In the New York ISO documents on this issue, a “spread” is acknowledged to exist between the marginal cost of generation in New York City ($159/kW of Installed Capacity per Capability Year) and the rest of the state ($85/kW). Therefore, any AC transmission project that reduces the New York City locational capacity requirement would save the City’s load-serving entities $74/kW per year in capacity payments.

Under FERC’s SMD, there is a principle that those who create such benefits should be paid for them. But under current practice, the only payment that a merchant transmission investor would obtain is the CRRs (FTRs or TCCs, depending on the pool). Merchant transmission projects should also be paid for any reductions in locational capacity requirements they create.

In a power market like New York, where locational capacity requirements and “capacity demand curves” (or their functional equivalents) exist, merchant transmission projects that reduce such requirements should be awarded “Locational Capacity Reduction Payment Rights,” equivalent to the magnitude of the reduction in megawatts times the spread between the cost of capacity in the load pocket and in the rest of the market.

For example, suppose a 600 MW merchant AC line reduces a load pocket’s locational capacity requirement by 400 MW, and that the “capacity spread” between the load pocket and the rest

¹. See Long Island Power Authority, LIPA Energy 2002-2011, page 7-24. The quantum whereby new DC versus AC power lines reduce the locational capacity requirement is an open question.
of the market is $74-kW/yr. In this case, the project would obtain a long-term contractual payment of $29.6 million/yr (400 MW x $74/kW *1000).

In this way, the “Locational Capacity Reduction Payment Right” allows merchant transmission projects to capture the value of their contribution to the capacity markets². As such, it would be appropriate for them to be paid in the form of relatively long-term contracts with the load-serving entities that have the capacity obligation. Such long-term contracts, in turn, would form the basis for the debt part of the financing of the merchant transmission lines.

In addition to the “Locational Capacity Reduction Rights”, the AC merchant line would be allocated FTRs or CRRs, which are monetized in the energy (and not the capacity) market. Because these are volatile revenues, it would be appropriate for equity investors to finance this part of the merchant transmission project.

Taking the fixed (LCRPR) and the variable (FTR) revenue streams together, we can imagine a proforma for an AC transmission project. Assume the 600 MW AC expansion referred to earlier costs $300 million. Assume it reduces the LSE’s locational capacity requirement by 400 MW and that the “capacity spread” with the rest of the market is $74-kW/yr. Assuming a 20-year project life, the $74/kW payment would provide two-thirds of the required cash flow to finance the project on a merchant basis.

The remainder would be “TCC revenues” which would be “at risk” money suitable for equity investors. To make the project financible, the energy spread in the day-ahead market between the City and whatever nodes upstate would be chosen for the TCC calculation would have been deemed to be large enough by investors to make it worth their while.

There are many issues that have to be discussed in implementing this proposal. The extent to which a new transmission connection or an upgrade should result in reductions in the locational capacity requirement depends (in the case of New York) on a “one day in ten year” criterion known as the “Loss of Load Expectation.” Other technical circumstances in the load pocket and how the ISO interprets these requirements will determine the extent to which the new tie line reduces the locational requirement.

However these more technical consideration are resolved, the fact of the matter is that, while some DC projects are under development, merchant AC transmission investment is at a standstill. Especially because regulatory risk is deemed to be high, and investment dollars are wary of the electric markets, merchant AC projects will need some “firm”, “base load” revenue streams to get them going.

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² In New York, the ISO has taken a step towards this by implementing a “UDR” (unforced deliverability right) – but this applies to controllable lines only and was designed to accommodate the first wave of merchant transmission projects, which have all been DC.