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DATE:	**November 6, 2019**
TO:	**Federal Energy Regulatory Commission**
FROM:	**Joseph Bowring, Independent Market Monitor for PJM**
SUBJECT:	**Grid Enhancing Technologies (Docket No. AD19-19)**

As stated by the Commission, grid-enhancing technologies (GETs) can increase the capacity, efficiency, or reliability of transmission facilities. The Commission can change regulatory approaches to GETs by addressing incentives or by direct requirements for the adoption of grid-enhancing technologies. For purposes of this discussion, GETs include, but are not limited to: (1) power flow control and transmission switching equipment; (2) storage technologies; and (3) advanced line rating management technologies.[1]

The transmission grid defines the network which permits the functioning of competitive wholesale power markets for energy, capacity and ancillary services. But the definition of competitive wholesale power markets also includes the transmission grid itself. As initiated in Order 1000, there is no reason to exempt the transmission grid from competition for innovative approaches to upgrades, expansions and improvements.

The capability of the transmission grid to transmit power affects every aspect of the energy and capacity markets. These include direct impacts on energy and capacity prices, the frequency and level of congestion in the day-ahead and real-time energy market, day-ahead nodal price differences and the associated value of FTRs, real-time nodal price differences, locational price differences in the capacity market, the need to invest in additional transmission capacity, the need to invest in additional generation capacity, the location of new power plants, and the interconnection costs for new resources. These also include potential impacts on competition in the energy and capacity markets as the choice of where to place power flow technology and how to operate the technology will affect the economics of existing power plants. The impact of transmission facility capability on markets is a function, in part, of the actual capability of the facilities, of new technologies that may enhance that capability, of how the capability is measured (line ratings), of how the new technologies are used by the RTO/ISOs, and of the use or modification of measured capability by the RTO/ISOs. While this workshop focuses on the technologies that can affect the capability of the transmission grid, the measurement of the impact on that capability, the actual use of the technologies by the market operator and the impacts of those uses should also be examined.

1 (FERC, Grid Enhancing Technologies, Docket AD19-19-000, Supplemental Notice of Workshop, November 11, 2019.)

For straightforward approaches like ambient adjusted line ratings (AAR), the Commission should require immediate adoption. Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. PJM real time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings. For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real time conditions and to help ensure that real time prices are based on actual current line ratings.

For dynamic line rating (DLR) technologies, the Commission should require significant pilots and analysis of the results and the applicability of the results, to be completed within a defined time period. It is likely that some application of DLR should be required by the Commission in the near future. The Commission should open the provision of DLRs to competition with the result that the lowest cost provider would make the investment.

Given the weaknesses of the current transmission cost of service regulatory paradigm as a mechanism for competitive, efficient and flexible outcomes compared to a market approach, no new technologies should be included as transmission assets unless it is unavoidable. In the case of batteries, there is no reason to include batteries as transmission assets. There are market opportunities for batteries to compete and if batteries are economic, private investors will build batteries, take the associated risks and receive the associated rewards. Inclusion of batteries as a transmission asset is likely to have a negative impact on competition to provide batteries.

The goal with respect to GETs should be to establish a regulatory approach that relies on Commission directives when appropriate, and that, to the maximum extent possible, relies on competition and market incentives for the construction and operation of GETs. The fact that GETs are not already well established in U.S. wholesale power markets is evidence that the cost of service paradigm is not working to provide incentives for efficient, least cost solutions. The market paradigm does not rely on cost of service ratemaking, including paying higher rates of return to regulated utilities to encourage innovation. The cost of service approach is not well suited to providing incentives for cost cutting innovations. Under the cost of service approach, the regulated companies prefer higher levels of investment to lower levels of investment to reach the same goal because higher levels of investment lead to higher total returns for the regulated companies.

Simple math demonstrates that paying higher rates of return within the cost of service paradigm cannot and will not work to provide effective incentives to investment in efficient and least cost transmission solutions. By definition, if an investment in GETs costs significantly less than an investment in transmission facilities with a comparable impact on load carrying capability, a higher rate of return on the GETs investment, within any conceivably reasonable bounds, could never make a regulated transmission owner indifferent. Under cost of service regulation, the regulated transmission owner will always prefer a project with higher investment costs.

Paying above market returns to transmission owners to take actions which are not in their financial interests is not an efficient or effective approach to opening the system to new technology. As seen in the experience of generation development, the current world cost of capital is relatively low and well below regulated rates of return. Competitors are likely to be willing and able to make the investments at lower cost than a regulated transmission company, even if the competition were only to receive regulated revenues based on the competitive offer. Given that there is an incentive to not engage in the requested activities, paying higher returns is not the best way to have new technology implemented.

The market paradigm for GETs can be defined in a variety of ways and include a variety of dimensions. There is no final, clear answer on the best market design for GETs at the moment, but there a number of potential approaches that should not be considered as part of a market paradigm.

The market approach does not rely on counterfactual benefit sharing. It is not reasonable to rely on ongoing real time counterfactual analysis of what price differences would have been, or how the markets would have cleared, but for the investment in power flow control technology, for example. Such counterfactual approaches are complex, subject to increasingly difficult interaction effects as more new investments are made, subject to subjective judgments and subject to significant measurement error as demonstrated by the measurement issues for demand side resources. Benefit sharing is a variant of the standard regulatory paradigm rather than a market approach, but without the benefit of a defined rate of return which would limit the excess compensation that is likely under this approach.

The market approach does not rely on cost benefit analysis as the basis for compensation. Cost benefit analysis is speculative by definition and is based on expectations about an uncertain future. Assuming that an appropriate metric for defining benefits were defined, cost benefit analysis cannot address the dynamic intertemporal variability of congestion or the dynamic locational variability of congestion or the more general changes in market dynamics over the likely life of the assets. In the case of power flow control, benefits are the result of the dynamic dispatch of the technology that can affect the market in unpredictable ways, including higher costs for some customers and lower costs for other customers. Cost benefit analysis as currently used to support transmission investment in PJM also includes subjective judgments, incomplete definitions of costs and benefits, and an incorrect definition of congestion. Cost benefit analysis is a variant of the standard regulatory paradigm rather than a market approach, but without the benefit of a defined rate of return which would limit the excess compensation that is likely under this approach.

Using a competitive, market based approach seems to be a straightforward solution to the incentives issue. But it is not. The optimal roles of market operators and market participants need to be defined. There are complexities in defining the metrics for where a technology should be located on the network. There are complexities in the interactions between competitors and existing transmission companies. There are complexities in defining how the technology should be dispatched once it is installed. There are complexities in defining exactly what is being bought and sold. For example, selling the rights to FTRs on a path is not a workable solution for compensating new power flow control technologies. One issue is that this approach would create incentives to not fully relieve the constraint. If the constraint were fully relieved, the FTR would have no value. The simple difference in prices between nodes is not a good measure of the need for a new investment. When FTRs are defined based solely on day-ahead price differences and ignore real-time price differences, FTR value is not a good metric of benefits.

The Commission should support the market paradigm and focus on developing the details of a market approach. There is no reason not to begin immediately. Any initial design should avoid the creation of vested interests that would inhibit the continued development of competition. A first step could be competing to receive regulated revenues for the relevant technology, e.g. DLR technologies. After a competition to determine the lowest offer to install a defined technology over its defined life, the winner would receive its competitive offer price for the asset over its life based on performance guarantees. This would be a significant step in the direction of more comprehensive market based solutions.

As an example of the complexities of defining the benefits of GETs, the reduction in congestion is frequently cited as a metric of benefits. Some reports cite to increasing congestion in PJM and elsewhere as a reason to invest in GETs. Some have proposed receiving a share of reduced congestion as an incentive for adding GETs.

Congestion is frequently misunderstood. Congestion is not static. Congestion exhibits dynamic intertemporal variability and dynamic locational variability. More importantly, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid through GETs.

There is not in fact a secular trend towards increasing congestion in PJM. Figure 1 shows actual monthly congestion in PJM from January 2008 through June 2019.[2]

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[2] *2019 Quarterly State of the Market Report for PJM: January through June, Section 11, Congestion and Marginal Losses.*

Figure 1 PJM monthly total congestion cost: January 2008 through June 2019

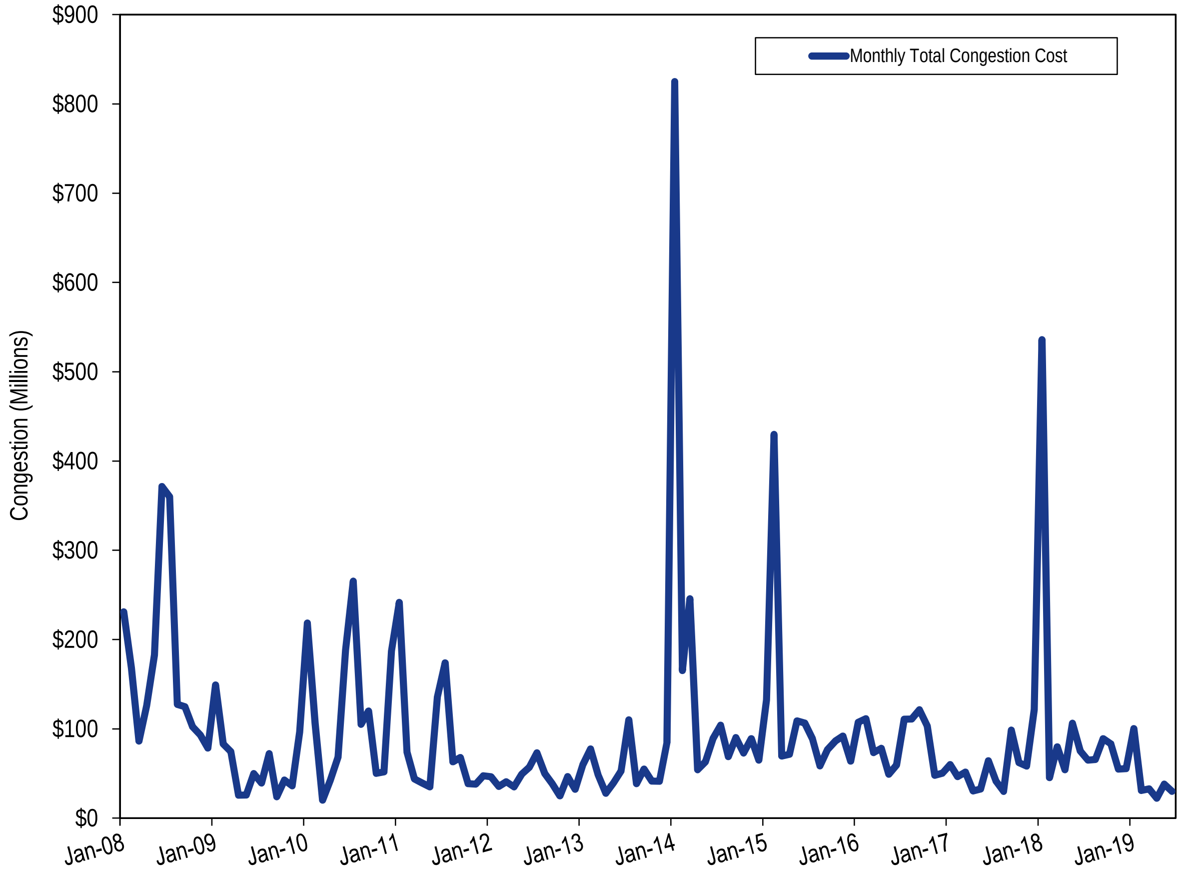

Figure 1 also shows that congestion is volatile on a monthly basis. Congestion is also volatile on an hourly and daily basis. For example, higher congestion can result from changes in seasonal and daily/hourly fuel costs. In 2018, congestion increased significantly for the entire year as a result of high gas costs associated with cold weather that occurred for only a relatively short period of time in the winter.

The level and distribution of congestion at a point in time is a function of the location and size of generating units, the relative costs of the fuels burned and the associated marginal costs of generating units, the location and size of load and the locational capability of the transmission grid. Each of these factors changes over time.

The geographic distribution of congestion is dynamic. The nature and location of congestion in the PJM system has changed significantly over the last 10 years and continues to change. The nature and location of congestion in PJM can also change from one day to the next as a result of changes in relative fuel costs. As a result, building transmission or adding GETs to address one specific pattern of congestion does not make sense, unless the technology can be easily moved to new locations as conditions change. The transmission system is only one of many reasons that congestion exists. The dynamic nature of congestion and the multiple, interactive causes of congestion make it virtually impossible to identify the standalone impacts of an individual GET investment, exacerbated by the addition of multiple GETs.

At a more fundamental level, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid through GETs.

When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load. The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the higher price for all energy including energy from low cost and energy from high cost generation while high cost generators are paid the high price at their bus and low cost generators are paid the low price at their bus.

Congestion is defined to be the total congestion payments by load in excess of the total congestion credits received by generation.

If FTRs worked perfectly and were assigned directly to load, FTRs would return all congestion to the load that paid the congestion. Congestion is not a cost, it is an accounting result of a market based on locational energy prices in which all load in a constrained area pays the higher single market clearing locational price, resulting in excess payments which should be returned to load.

Counterintuitively, congestion actually increases when the transmission capacity between areas with lower cost generation and areas with higher cost generation increases but does not fully eliminate the need for some higher cost local generation. The smaller the amount of higher cost local generation needed to meet load, the more of the local load is met via low cost generation delivered over the transmission system and therefore the higher is the difference between what load pays and generation receives, congestion.