Wind Energy, Congestion Management, and Transmission Rights

Issue Brief

Issue Description/Problem Statement

Transmission congestion occurs when more power is scheduled or flows across transmission lines than the physical ratings of the lines. The problem of congestion has increased in recent years, due to a number of causes. According to the North American Electric Reliability Council (NERC), the advent of open access transmission and competitive bulk power markets is bringing new entrants and transactions into bulk power markets, causing the movement of power in “unprecedented amounts and in unexpected directions,” directions which were not contemplated when transmission systems were originally designed. Wind energy generation in Texas and California has been curtailed, for example, because the local transmission systems could not always handle the wind generation being fed into it.

NERC, and the regional reliability organizations that implement NERC standards, have historically used Transmission Loading Relief (TLR) procedures when the transmission system is in danger of being overloaded. There are several classifications of TLRs, ranging from Level 0 to Level 6. Transaction curtailments do not occur until Level 3, for non-firm transmission, and Level 5, for firm transmission. One problem with NERC’s TLR process is that, other than firm versus non-firm transactions, it treats all transactions essentially equally, so transactions are curtailed on a “pro rata” basis. The process does not offer market participants a chance to value their transactions independently, i.e., to set an economic value or strike price that would define when their transaction would or would not go through. In essence, the NERC reliability rules were not designed as a congestion management tool for allocating scarce transmission capacity to maximize economic efficiency but instead were intended to prevent transmission facilities from overloading in an emergency.

Ironically, transmission may be underutilized in some regions of the country, even if there is no reported available capacity on the transmission system. For example, the Western Governors Association reported in 2001 that at least 60% of the time, transmission paths in the Western Interconnection are used at half of their rated capacity. Part of this is due to the nature of transmission service that is divided between firm and non-firm point-to-point service, and network transmission service. Firm point-to-point transmission service is available on an around-the-clock basis, while non-firm transmission service can only be used when transmission service is available. Network transmission service is where a transmission customer, typically a load-serving entity such as a transmission-dependent utility, can integrate load and generation resources over a certain area without having to make multiple firm transmission arrangements. Since wind generators contribute supply, network
A number of transmission customers reserve firm service and use what they need. The problem for wind generators is that the existence or threat of transmission congestion, even if for a few hours per year, may prevent a new wind generating plant from coming on-line, unless the wind generator agrees to finance necessary transmission improvements, the cost of which may make the wind project uneconomic. Consequently, a significant number of high quality wind resource sites cannot be developed because developing these wind projects could increase transmission congestion, and there is insufficient available transmission capacity to fully accommodate the wind plant. Indeed, transmission congestion is a central issue in transmitting wind energy south from Wyoming to Denver, from west to east in Texas, in the upper Midwest, and in various parts of the Pacific Northwest.

Furthermore, emerging congestion management strategies may be incompatible with the variability of wind, although this depends on the particulars of the congestion management strategy, and more importantly, who pays to mitigate congestion.

**REGULATORY BACKGROUND**

Order 888, issued in 1996, required transmission owners under FERC jurisdiction to offer access to their transmission systems, net of serving their native loads. Congestion management was mostly handled through generation re-dispatch but mostly to maintain grid reliability, not for economic reasons. The Order 888 pro forma tariff allows transmission providers to redispacth to relieve transmission congestion at the request of a transmission customer if it costs less than constructing network upgrades, and if the transmission customer agrees to pay incremental redispacth costs to the transmission provider. However, FERC and transmission providers could never agree on a rate formula for economic redispacth, and as a result, redispacth to relieve transmission congestion for economic reasons does not occur often.

In Order 2000, the Federal Energy Regulatory Commission (FERC) stated its intention that RTO proposals should explore market-oriented mechanisms for alleviating congestion. It said that RTOs should ensure that:

The generators [that] are dispatched in the presence of transmission constraints are those that can serve system loads at least cost, and limited transmission capacity is used by market participants that value that use most highly...A workable approach should establish clear and tradeable rights for transmission usage, promote regional efficient dispatch, support the emergence of secondary markets in transmission rights, and provide market participants with the opportunity to hedge locational differences in energy prices.  

However, Order 2000 was voluntary, and implementation under Order 2000 has been quite slow. Currently, FERC has fully approved only two RTOs—the Midwest ISO and PJM—under Order 2000, although others have been provisionally approved.

In July 2002, FERC initiated a rulemaking on Standard Market Design (SMD) in an attempt to unify these sometimes-
inconsistent regional approaches. The proposed SMD envisioned use of locational marginal pricing (LMP) to determine congestion costs and tradable financial rights to allow transmission customers to hedge against these costs. These and alternative approaches are described in more detail below. \(^2\) In April 2003, FERC released its “White Paper” that clarified and limited elements of the proposed SMD rule. For example, in the proposed SMD rule, FERC required the use of LMP but in the White Paper, FERC left the determination on congestion management to regional state committees. \(^3\)

**Emerging Congestion Management Approaches**

It is widely recognized that the NERC TLR rules are insufficient to allocate transmission capacity to maximize economic efficiency, and a number of different regional practices are emerging. Loosely, they can be categorized into financial (such as LMP) and physical congestion management strategies (such as zonal or flow-based congestion management approaches).

**Locational Marginal Pricing:** LMP involves measuring the price of electricity by delivery and receipt points, or “nodes”, and attributing the difference in market-clearing price between nodes to transmission congestion. The LMP model assumes that in the absence of transmission congestion, the least expensive electricity source would be used to serve an increment of load; however, if congestion is present, then a more expensive source of power must be used. The difference in price between the least expensive option and the option actually used is attributed to congestion, and is assigned on a pro-rata basis to the transmission service customers whose transactions are using the affected nodes. Transmission customers can obtain financial transmission rights (FTRs) to hedge against congestion charges. These financial rights may be allocated to transmission customers, available through auction, or a combination of the two. Under a nodal or LMP approach, market participants need not obtain physical transmission capacity reservation, or physical right, to transmit energy. LMP is used in PJM, New York and in New England, and is proposed in California and in the Midwest ISO.

**Physical Transmission Rights:** Physical transmission rights means that a transmission customer must have control of a MW of transmission in order to transmit across a congested interface. The interfaces may be defined at entry and exit points of defined zones or along defined energy paths, and transmission capacity must be scheduled in advance. These methods allow points of congestion to be identified and valued ahead of time, giving market participants an

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\(^3\) FERC said any congestion management system other than LMP must meet the following principles: protect against market manipulation; promote the efficient use of the transmission grid; promote the use of the lowest cost generation; assign cost responsibility to those that cause congestion costs and assign benefits to those that reduce congestion costs; reduce involuntary transmission service curtailments; and be compatible with congestion management systems used by other RTOs and ISOs in the same interconnection (i.e. Eastern or Western Interconnection).
opportunity to readjust delivery schedules, or the system operator time to plan congestion clearing actions. In addition, the physical transmission rights may be available by auction or via some form of secondary market. There are two main types of congestion management strategies under a physical transmission rights approach:

- The zonal approach defines an area or region that typically has transmission congestion and applies a physical rights congestion management strategy. Congestion zones can simplify the congestion management process by reducing the number of markets that participants would need to monitor, and power marketers have tended to prefer zones for this reason.
- The flow-based approach is similar, but models congestion along defined “commercially-significant flowgates” instead of between zones.

Transmission rights under zonal and flow-based approaches can be implemented with physical or financial rights, but they have mostly been proposed using physical rights. For physical rights, under either zonal or flow-based approaches, a limited number of firm physical rights to transmission capacity are distributed via auction or through another allocation process. Only those holding physical rights can schedule transmission, usually at a predetermined price, when transmission capacity is constrained. A secondary market can be designed to trade such physical transmission rights. Other transmission customers can submit non-firm schedules, subject to curtailment, or rely on holders of physical transmission rights to re-dispatch generation to accommodate transactions.

While this approach can help manage congestion between zones or on a flowgate, it may not accurately assign the costs of congestion that appears within a single zone or outside of a designated flowgate, since congestion costs are not measured in those instances. For this reason (among others), FERC has expressed a preference for the nodal or LMP approach in its proposed SMD rule and in the April 2003 White Paper.

**ISSUE IMPORTANCE FOR WIND**

Without careful consideration of the operational realities of generators that rely on variable resources such as wind, rules affecting congestion management and transmission rights can have the unintended consequence of making wind generators simply unable to participate in wholesale power markets. Even when such rules are written with complete neutrality to fuel source, they can still have the effect of preventing even high-quality, high-value wind or other generating resources from coming to market.

Wind generators face two problems under the zonal or flow-based approaches. First, the requirement that transmission transactions be scheduled in advance disproportionately impacts wind generators, since wind resource availability cannot be accurately forecast more than a few hours ahead of time. Faced with this requirement, wind generators must either schedule in advance and carry the risk of not meeting their schedules, or refrain from scheduling altogether and attempt to sell energy into real-time markets, if such a market exists. Second, wind’s variability may force wind generators to over-purchase transmission rights ahead of time to cover their potential generation or risk being curtailed. These transmission rights tend to be in large, flat blocks (e.g., five day by sixteen hour blocks) that tend to be far more than what wind generators need.
OPTIONS FOR RESOLVING THE ISSUE

There are several potential solutions to these problems. One is for a wind generator to simply enter into a power purchase agreement with a utility that then assumes the scheduling and transmission arrangements. If the power purchase agreement is in effect before a utility joins a RTO, then this and other agreements may be part of a “grandfather” arrangement, where the RTO follows existing contract terms in dispatching the power. If a utility is part of a RTO, the utility would have to request transmission service from the RTO. If there is insufficient transmission capacity, then transmission upgrades may have to be performed in order to accommodate the wind energy.

The other potential solution under the zonal or flow-based approaches is the establishment of a deep, liquid secondary market in tradable physical transmission rights in a RTO, where holders of these rights can split off the transmission rights they don’t need and sell them to other parties. This can be thought of as equivalent to selling strips of transmission rights, such as strips of Treasury Bonds in financial markets. While secondary markets in transmission rights are often envisioned, they have not emerged in practice, in part because RTOs have not yet designed the primary transmission rights market to allow a secondary market to emerge. Also, a “chicken and egg” situation exists where smaller strips of transmission rights are not made available because the demand is not expected, and transmission customers do not attempt to secure smaller strips of transmission rights because of lack of supply.

At least in part because of these problems with physical rights, wind generators tend to favor the nodal and LMP approach because they are not required to schedule in advance or to purchase transmission rights they either cannot use or cannot sell. Furthermore, a “load pays” arrangement is in place in PJM, New York, and New England, and proposed in the FERC SMD, meaning that load-serving entities are responsible for congestion and arranging for hedging against congestion. Effectively, congestion management is transferred away from generators to load—wind generators simply operate and provide energy to the grid as the wind resource is available and take the market price for their generation. Still, financial arrangements can be set up badly for wind generators. For instance, wind generators would not benefit if generators, rather than load, were responsible for congestion, and congestion rights were allocated rather than auctioned. As with a physical rights system, a deep and liquid market in transmission rights would be necessary if generators were responsible for congestion rights in a nodal system, rather than load.

Finally, one solution is simply to free up additional transmission capacity through the use of distributed generation or demand response in areas with transmission congestion, or expand existing transmission or build new transmission in order to alleviate transmission congestion. This raises a number of issues such as who pays for expanded or new transmission that are beyond the scope of this paper.

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