The Challenge of Transmission and Large Offshore Wind Energy Facilities in New England

For large wind farms remotely located from load the cost of transmission poses a significant obstacle. This will be a major issue with offshore wind development as well. It raises a fundamental question associated with transmission development– Who pays?

The developer of a generating facility is typically responsible for paying for the transmission that connects the generator to the bulk electric transmission grid (often referred to as a "gen tie"), as well as any upgrades on the bulk system that might be needed in order to ensure that the new interconnection does not adversely affect the reliability of the overall system. For a variety of reasons this is difficult for large wind resource areas. Places in the country and around the world that have the greatest success in developing wind resources have resorted to some form of socialized or system wide rate based payment for the transmission developed to support wind farms.

Because wind farms have capacity factors below 50%, except in rare occasions, developers are put in the position of deciding how large to size the line in order to move their energy to the rest of the grid. For example, a 100 MW wind farm will not produce 100 MW of power 100 % the time, yet it is desirable to have enough transmission capacity available to transmit the 100 MW when it does. Therefore, developers are likely to "oversize" the line even though the full capacity of the line will only be used less than half the time. For a smaller wind project located a relatively short distance from the bulk transmission grid, the cost of the gen tie can be absorbed by a single developer and figured in to the overall cost of a project. To fully exploit a region that has a large wind development potential, but which is a great distant from load, such as the Tehachapi Mountains of California, the Texas panhandle, the mid-West states of North & South Dakota, or offshore areas, its unlikely and unreasonable to expect that a single developer will build one line large enough to serve the whole region. While it may seem a simple solution to have two or three developers share in the cost of a line, the credit worthiness, individual construction risk, and multiple other factors known simple as "project-on-project risk" makes the financing of multiple user lines through the market highly unlikely. Therefore, other financing approaches are required if government policy mandates are to be achieved in a timely manner.

California, which has a mandate to get 20% of its energy from renewable resources by 2010 and a proposed goal of 30% by 2020, has taken a policy lead to provide a mechanism for addressing the financing of transmission lines that are large enough to serve the full wind development potential of a region, independent of the involvement of a single developer. Led by the California Public Utilities Commission and its desire to provide more transmission access to the estimated 6,000 MW of wind resources in the Tehachapi Mountains in southern California, the California Independent System Operator (CAISO) sought and received a declaratory order from Federal Energy Regulatory Commission (FERC) authorizing a "third" category of transmission lines that could be socialized if they served "location constrained" resources. This was a departure from previous FERC policy in that had only authorized the rate basing of projects needed for reliability or market efficiency and which were integral to the bulk transmission system. A transmission line that was "radial" and not integral to the rest of the transmission grid was simply considered a gen tie whose cost would be paid for by the generation

developer. Under the Tehachapi model all ratepayers served by a California regulated utility share in the initial cost and risk of building a transmission "trunk-line" to location constrained renewable resources areas. The initial cost and risk of developing a trunk-line to a location constrained area is borne by the CAISO ratepayers. As projects are developed in the location constrained area the renewable energy developer pays for its proportional share of the cost of trunk line based on the capacity of the line that it uses. As new projects come on line they in turn pay for their proportional share until the capacity of the line is filled and fully paid for. At that point ratepayers are no longer responsible for the cost of the line. This approach to building a renewable transmission line has yet to be used in California.

Texas leads the nation in wind development, with more than 7,000 MW of installed generation, which is twice the amount of renewable energy of Iowa (2,800 MW) and California (2,500 MWs), the next two largest wind development states. It has done this by designating competitive renewable energy zones or "CREZs" throughout the state and socializing the cost of transmission that serves renewable energy zones. In 2007 it designated five CREZs and had the state's regional transmission organization (RTO), the Electric Reliability Council of Texas (ERCOT), identify and cost out different build out scenarios ranging from $3 billion to $6.4 billion. In July 2008 it selected the $5 billion alternative that will enable the development 18,500 MW of new wind resources in the state. It then bid out the construction of the transmission lines to transmission developers, including incumbent Texas utilities and independent transmission developers. This January eight developers were selected. The cost to consumers for the program is estimated to add $4.00 per month to a residential customer's electric bill.

Texas and California share the benefit of having a single state RTO with one state public utility commission. Therefore, it is easier for them to reconcile state policy goals for renewable resources with issues of cost allocation. In fact in California it was the public utility commission that effectively pushed the CAISO to come up with a solution for cost allocation in the Tehachapi region. As we well know, this is not true of New England where the question of cost allocation is very contentious. In ISO-NE only projects needed for reliability or market efficiency qualify as "regionally benefit upgrades". The cost of the projects, which are identified through a regional planning process at ISO-New England, can be socialized across the region. Cost allocation is done on a state by state based on the percentage of demand of peak load for each state. So Massachusetts pays 45 percent of a regional benefit upgrade project, Connecticut pays 27 percent, New Hampshire 9%, Maine 8%, Rhode Island 7% and Vermont 4% (the percentages are adjusted on a regular basis). The contentious nature of cost allocation as applied to renewable energy resource development was witnessed most pointedly with the Maine Power Connection. Massachusetts regulators strongly objected to applying market efficiency criteria to the Maine Power Connection under which its rate payers would pay 45% of the cost for a line they deem to by a gen tie, the cost of which should be borne by the wind farm developer.

The New England state regulators have been attempting to collaborate around a common interest to resolve the cost allocation question and how it relates to renewable energy development, but individual state RPS goals and in-state economic development issues complicate the discussion. Moreover, New England lacks a mechanism within the ISO-NE Open Access Transmission Tariff (OATT) under which the

cost of a transmission line built to access renewable resources could be socialized, like the California Tehachapi model. In short, progress in New England has been slow.

One of the attractions of the recent Northeast Utilities and NSTAR proposal to bring 1,200 MW of power from HydroQuebec to New England through a participant funded transmission line is that it avoids the testy issue of regional cost allocation and the addition of more socialized transmission costs into the New England rate base. The project, which does not provide RPS eligible generation, would be financed through a 20 year, long-term contract with the price of the transmission line rolled in to the price of the electricity carried over the line. The proposal looks like a traditional gen tie. The long-term contract, which New England moved away from when it restructured the energy market, would need to be approved by public utility commissions, at which time determination of who takes on the risk of the development would need to be determined. This mechanism (the provision of long-term contracts that roll the cost of transmission and energy into one bundle) could be used as a way to support the development of renewable resources in New England. The Massachusetts Green Communities Act, for example, requires its state's utilities to issue requests for proposals for long-term contracts for in-state renewable energy projects.

Finally, there is action at the federal level that addresses transmission, renewable energy development, and cost allocation. Senate Majority Leader Harry Reid's bill includes provisions to designate renewable energy zones where there are areas with more than 1,000 MW of renewable energy. It also includes a section that would allow FERC to regionally or interconnection-wide allocate the cost of transmission that serves a renewable energy zone. The bill would apply a California style model of paying the initial cost of a line large enough to provide the full transmission capacity needed for a region through a rate based cost allocation and then having developers pay down the cost as renewable energy projects come on line.