Energy Regulatory Challenges Facing Renewable Projects In 2011: Successful Projects Will Account for Interconnection and Transmission Issues Early in the Process

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Both federal and state governmental agencies are strongly emphasizing diversifying our energy generation portfolios by encouraging greater reliance on renewable energy resources. Because many viable renewable resource sites (especially solar, wind and hydro) are located far from the existing grid, interconnecting a renewable energy resource to the grid could trigger the need for tens of millions—and in some cases, hundreds of millions—of dollars in interconnection/transmission costs, which could be prohibitive for many projects. The Federal Energy Regulatory Commission (FERC)[1]—the federal agency that has jurisdiction over most disputes in this area—is considering in different proceedings various objections to how these costs are allocated to such projects.

Interconnection/transmission issues have thus become "gating" issues for renewable projects—i.e., issues that should be addressed in the very early stages of a project. There are other FERC regulatory issues that can also impact the value of a project, including how to structure the project ownership in ways that would be attractive to lenders and investors. Failure to account for such regulatory issues up front might result in project sponsors spending unnecessary time, resources and money on projects where the interconnection/transmission costs or other regulatory risks may doom the project from the outset. These issues are especially important for the recent newer entrants to the renewable energy development field, such as farmers, ranchers and real estate developers desiring to access the U.S. market. Such newer entrants may have limited experience with the interconnection/transmission process and related FERC regulatory issues. In fact, appropriate ways to address these issues may seem counter-intuitive to those not familiar with energy projects.

This Article will focus on these gating interconnection/transmission and related FERC challenges to renewable energy development. While some of these issues seem equally applicable to any type of electric generation project, renewable projects raise special challenges because very desirable renewable energy project sites are often far from the existing transmission grid and population centers. Accessing the grid from these remote sites triggers the need for building hundreds of miles of interconnection and transmission lines to the grid, and potentially the need to construct new or to refurbish facilities on the transmission provider's side of the point of interconnection, so that power can be delivered from the projects to customers. Besides the cost and financial issues, other regulatory issues involving the intermittent nature of renewable resources must also be understood in order to structure the project in the most beneficial manner for optimal return on project sponsors' investments.

Cost Allocation of Transmission System Upgrades

High transmission/interconnection facility costs can present daunting financial obstacles for renewable projects, including smaller projects. But how could small projects possibly compel the need for such expensive upgrades? In some cases, the new project is the "tipping point" project, where a constrained transmission system, already taxed in delivering power from existing generation projects to customers, cannot accommodate any new generation without constructing significant new facilities or upgrading existing ones. A new transmission line is typically not sized just to accommodate incrementally a single new project; instead, it is sized to permit deliveries from the next wave of anticipated projects. Where very lengthy interconnection lines need to be built, land needs to be acquired or easements obtained, and various local state and federal approvals must be secured.

How can project sponsors and developers find out early in the process whether expensive upgrades will be needed to connect a project to the grid? Regional transmission organizations (RTOs), independent system operators (ISOs) and other transmission providers conduct studies to determine the cost of interconnection for all projects, including renewable projects. Some RTOs have procedures for generators to obtain preliminary information about potential interconnection costs and potential constraints. The California Independent System Operator, for example, provides prospective interconnection customers with access to Interconnection Base Case Data in order to analyze and model their proposed projects at various interconnection points before a formal interconnection request is submitted. Such information is offered in order for prospective interconnection customers to determine whether some interconnection points are cost-prohibitive before any deposits are posted or formal studies are requested. The deposits alone can be in the $10,000 to $120,000 range.[2]

In some cases, prospective projects are studied by RTOs in a "cluster," i.e., projects slated to go on line around the same time in the same general area. The focus is thus on a broader group of generators instead of upon a single "tipping point" project, and this helps ensure that all the "clustered" generation projects can transmit their output to the grid. The "cluster study" approach also enables the transmission provider to allocate costs among a larger number of planned projects, instead of just attributing them to the "tipping point" project. Even in a situation where costs are being shared across a larger group, many project sponsors cannot afford their share of costs. If such cost-constrained projects drop out of the cluster study, the remaining projects will have to bear a higher proportion of the prospective costs. On the other hand, the more projects that drop out, fewer network upgrades may be needed with less total costs to be shared by the remaining projects.

The cost allocation process overseen by FERC is a key element in the renewable project development process. Generally, all direct interconnection from the generator to the grid are borne by the generator/interconnection applicant. New projects may also trigger the need for new substations and transmission facilities and lines on the transmission provider's side of the interconnection (known as "network upgrades"). The cost allocation methods differ between transmission providers. The general rule under FERC Order No. 2003 (Standardization of Interconnection Practices)[3] is that the generator recoups the network upgrade costs it pays up front over a five-year period in the form of transmission services credits. Costs of transmission service for the project are paid for, in effect, by these credits, which are earned from the network upgrade payments made by the generator. Some RTOs, such as PJM Interconnection, L.L.C., allocate almost all such costs to the generator. For transmission providers that are not members of an RTO, FERC's

Order No. 2003 standard would apply unless the transmission provider has obtained FERC approval for a deviation from FERC's standardized rules.[4]

Disputes over Allocation of High Cost Network Upgrades can Make or Break a Project

Who pays for expensive network upgrades are a critical element in renewable project development. The Midwest Independent Transmission System Operator (Midwest ISO) changed its reimbursement standards to allocate 90 percent of the network upgrade costs to the project causing the upgrade.[5] In a recent FERC proceeding, the Midwest ISO studied the Community Wind project in Minnesota, together with a number of other projects proposed in the area, with network upgrades potentially costing hundreds of millions of dollars, primarily relating to the $700 million Brookings Line. The network upgrade costs would be shared by the projects in the cluster based on their relative size.[6] For example, a 10 megawatt (MW) project would have been allocated approximately $39 million, which could be cost prohibitive for a project of this size.

The affected generators objected to being directly allocated any of these costs, arguing that the transmission owners in the area had previously sought regulatory approvals for the new Brookings Line due to its mandate to promote system reliability. Consequently, the generators argued, the $700 million cost should not be directly allocated to them, but instead should be shared by all transmission customers in the area, thereby greatly reducing the generators' cost responsibility for the Brookings Line. FERC ruled at that time that the Midwest ISO had not demonstrated that the Brookings Line and related network upgrade costs should be directly allocated to the affected generators in the cluster studied, but concluded this year that the Midwest ISO could later re-file its cost allocation proposal after supporting it with appropriate studies.[7]

Multi Value Projects

Although the Midwest ISO's recent policy is to allocate 90% of the costs of network upgrades to the specific generator interconnection project causing such need for transmission upgrades, it has recognized that certain upgrades offer widespread benefits to the transmission system as a whole. In a recent filing with FERC, the Midwest ISO proposed to roll in the cost of "multi value project" transmission facilities that provide system-wide benefits. Multi Value Projects (MVPs) are those transmission projects that are 345 kilovolts (kV) or above, and benefit all customers within the Midwest ISO planning region by mitigating congestion, enhancing reliability, and reducing overall transmission costs. Following the established cost causation principle, the cost of such network upgrades of MVPs would be 100 percent allocated to all load and exports, based on usage, within the Midwest ISO footprint, rather than being assigned to a specific generation project sponsor.[8]

A number of the affected generators have argued that the Brookings Line should be treated as an MVP project, and the Midwest ISO's MVP filing noted that Brookings might qualify for such status. Although not addressing the Brookings Line specifically, the Commission largely accepted the Midwest ISO's MVP proposal, stating that it was an "important step in facilitating investment in new transmission facilities to integrate large amounts of location-constrained resources, including renewable generation resources, to further support documented energy policy mandates or laws, reduce congestion, and accommodate new or growing loads," and that it "provides a better balance for allocating cost responsibilities for large network upgrades associated with interconnecting with the electric transmission grid."[9]

A Wall Street Journal Editorial criticized FERC's decision, calling it a way to socialize renewable energy costs and to pass on exorbitant costs to ratepayers instead of allocating them to the renewable generators causing the need for the upgrade costs.[10] In a response to the editorial, all

FERC Commissioners argued that the order helps expand transmission, which enhances reliability and competition, which helps control costs to consumers.[11]

Illinois Commerce Commission v. FERC (Cost Causation and Benefit Tests)

FERC is also engaged in a new rulemaking in 2010 on Transmission Cost Allocation, [12] noting its proposed principles are built in part upon the decision by the U.S. Court of Appeals for the Seventh Circuit in *Illinois Commerce Commission v. FERC*.[13] Renewable developers will want to pay close attention to this rulemaking to see how it could impact their planned projects.

In *Illinois Commerce Commission*, the Seventh Circuit reviewed a FERC order which approved an RTO's proposed allocation on a pro rata basis among all utilities within its footprint the costs of new transmission facilities with a capacity of 500 kV or more. The Seventh Circuit criticized FERC's ruling because it did not demonstrate what benefits the parties burdened with the costs would receive. The court made clear that "FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members."[14] As there was no clear nexus between the "cause" of such costs and the benefit incurred, the Seventh Circuit concluded that FERC had not exercised reasoned decision-making. The FERC order was thus remanded for further consideration, where it is still pending.

Energy Regulatory Issues Affecting Value and Competitiveness of Renewable Resources

In response to either mandatory or "strongly encouraged" renewable energy portfolio goals, utility systems who must comply with these requirements often issue Requests for Proposals (RFPs) to buy power from these projects, and conduct competitive bidding programs to identify the most economical renewable resource. These power purchasers typically desire to designate facilities chosen through this process as "network resources" under the transmission provider's Open Access Transmission Tariff (OATT). One way to get a "leg up" on other competing generators responding to the RFPs is to obtain Network Resource Integration Service (NRIS). NRIS is an interconnection service that studies whether network upgrades would be needed if the capacity of the projects were injected into and delivered to any point on the transmission provider's system. NRIS does not confer any transmission rights and, as such, transmission service would have to be acquired separately. Nevertheless, it affords a potential purchaser of power from the project more information with regard to the cost that will be associated with obtaining power from the project. A utility purchaser that issues an RFP might well accord extra points to a proposal from a project that has already acquired NRIS service, because it helps verify that significant network upgrades will not be needed and the delays associated with constructing such upgrades will be avoided, making power from the renewable project available sooner.

The intermittent nature of renewable projects also impacts the scope and type of transmission service available. For example, for purposes of designating a renewable energy resource as a network resource, some RTOs—such as the Midwest ISO and Southwest Power Pool—will only allow designation of up to 20 percent of the project's total capacity for network resource.[15] If the project can demonstrate that it operates at a higher level, then further studies could be performed by the RTO, potentially indicating that a greater amount of the resource could be designated as a network resource.

The intermittent nature of renewable energy has also given rise to other types of special requirements from renewable projects with regard to ancillary services. FERC, for instance, issued a new Notice of Proposed Rulemaking in November 2010 to review whether special rules should apply to variable energy resources, such as wind facilities.[16] The outcome of this proceeding could impact the economics of operating renewable projects. In addition, some states may have their own special operating rules for variable renewable projects, such as in California, where the California ISO has obtained FERC approval[17] for certain new regulations and reactive power requirements.

Structuring Transactions to Minimize Regulatory Burdens

A project sponsor will also want to ensure the transaction is structured to minimize unnecessary regulatory burdens. The newer entrants to renewable project development will need to understand the energy regulatory issues in order to avoid structuring the ownership in a way that might be unattractive to lenders and investors. In the early stages of wind projects, for example, developers will secure rights of way, property rights, permits, and transmission rights and agreements to ensure the power can be delivered from the project to the point of interconnection within the transmission system. Typically, a project company is set up to hold these permits, rights, and eventual transmission facilities. However, prior to the transmission facilities becoming energized, such facilities should be transferred to the project generation companies, especially if the project companies hold Qualify Facility (QF) status under the Public Utility Regulatory Policies Act (PURPA).[18] QFs include solar, wind and hydro facilities under 80 MW. Once certified as QFs, they are eligible for certain exemptions from FERC regulation.[19] If there are multiple companies utilizing the same transmission/interconnection facilities, they should hold undivided ownership interests in these facilities.

Why transfer ownership of interconnection/transmission facilities to the generation project companies? Because those companies that qualify for QF status are exempt from FERC jurisdiction under sections 205 and 206 of the Federal Power Act (FPA),[20] including requirements that transmission owners offer non-discriminatory access to their transmission facilities to third parties. If the interconnection/transmission facilities are left in the non-generation project company, it will be subject to such open access tariff filing and service requirements. Transmission companies are not eligible for QF status; however QFs can hold interests in interconnection/transmission facilities needed to interconnect wind turbines to the grid, and are eligible for the exemption from OATT filing requirements under section 205 of the FPA.[21]

Budgets Should Account for the Effect of Energy Regulatory Issues

In developing budgets for legal/consultant expenses for relatively small renewable projects, some might assume that the smaller the project, the less the expenses. If someone spent $500,000 in legal and consultant expenses for a 100 MW project, they might assume that a 25 MW project would cost about $125,000 in legal expenses (one-fourth the size, so one-fourth the expenses). However, the costs of many of the permits/land rights/FERC authorizations will not vary that much based on size, as the same types of applications must be prepared and filed, with the size difference affecting just one portion of the applications. In addition, if projects are being developed by newer entrants to the energy project development field, they may not be as familiar with the types of state and federal regulatory issues and structures regarded as typical by developers and lenders with significant experience in the field.

It may take additional rounds of negotiations and revisions before contractual covenants are agreed to with smaller projects than is the case for larger projects with experienced parties to the transactions. Lenders also expect to see standard representations and warranties on public utility status under the FPA and holding company status under the Public Utility Holding Company Act[22] in key project documents and agreements. In addition to real estate rights and environmental permits, lenders will also want assurance that appropriate FERC certifications have been obtained. Project developers may also need to unwind some structures that, if not corrected, could result in unnecessary regulatory burdens. The myriad of complex regulatory and contractual filings and issues may be very unfamiliar to less experienced developers, thereby protracting negotiations and causing higher legal and consultant expenses.

Conclusion

Transmission and interconnection and related FERC regulatory issues will continue to loom as significant factors impacting renewable energy development. Understanding the issues of timing, costs, and related rights and obligations with regard to studies and agreements, as well as other requirements associated with transmission/interconnection standards, will enable developers to better focus on the most economical and efficient projects. Structuring projects to account for energy regulatory issues up front will also reduce unnecessary regulatory burdens and enhance the attractiveness of renewable energy projects.

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[1] The Federal Energy Regulatory Commission (FERC) is the federal agency that has jurisdiction over the interconnection and transmission access and cost issues that are the subject of this Article.

[2] *See, e.g.,* California Independent System Operator Corporation, Fifth Replacement FERC Electric Tariff, *Appendix U – Standard Large Generator Interconnection Procedures* § 3.5.1, *available at* http://www.caiso.com/2b18/2b18761133220.pdf.

[3] FERC, Final Rule, *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 (July 24, 2003), *order on reh'g*, Order No. 2003-A, , *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (Dec. 20, 2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (June 16, 2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

[4] Order No. 2003 at ¶ 826.

[5] *See* Midwest ISO FERC Electric Tariff, Fourth Revised Vol., No. 1, *Attachment FF - Transmission Expansion Planning Protocol* § III.A.d.

[6] Midwest ISO filing of the Amended and Restated Generator Interconnection Agreement, FERC Docket No. ER09-1581-000, Table 5 (Aug. 13, 2009).

[7] *Midwest Independent Transmission System Operator, Inc.*, 129 FERC ¶ 61,019 at ¶ 24 (2009), *order on reh'g*, 131 FERC ¶ 61,165; *order on reh'g*, 133 FERC ¶ 61,011 (2010).

[8] *Midwest Independent Transmission System Operator, Inc.*, 133 FERC ¶ 61,221 (2010).

[9] *Midwest Independent Transmission System Operator, Inc.*, 133 FERC ¶ 61,221 at ¶ 3 (2010). *See also FPL Energy Marcus Hook, LP v. PJM Interconnection, LLC,* 118 FERC ¶ 61,169 (2007)(concluding on remand that the generation facility had to pay the full $10.3 million of system upgrade costs because such costs would not have been incurred "but for" the generation facility interconnecting to the PJM grid).

[10] *The Midwest Wind Surtax.* WSJ, Dec. 30, 2010, at A14.

[11] Jon Wellinghoff, *et al*., *FERC Is Doing the Right Thing,* WSJ, Jan. 10, 2011, at A16.

[12] *See* FERC, Notice of Proposed Rulemaking, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 131 FERC ¶ 61,253, 75 Fed. Reg. 62,023 (Oct. 7, 2010).

[13] *Illinois Commerce Commission v. FERC*, 576 F.3d 470 (7th Cir. 2009).

[14] *Id.* at 476.

[15] Midwest ISO FERC Electric Tariff, Fourth Revised Vol., No. 1, *Attachment FF – Transmission Expansion Planning Protocol* § III.A(2)(c)(ii).

[16] FERC, Notice of Proposed Rulemaking, *Integration of Variable Energy Resources*, 133 FERC ¶ 61,149, 75 Fed. Reg. 75,336 (Dec. 2, 2010).

[17] *California Independent System Operator Corporation,* 132 FERC ¶ 61,196 (2010).

[18] 16 U.S.C. §§ 2601 *et seq.*

[19] 18 C.F.R. § 292.601.

[20] 16 U.S.C. §§ 824d and 824e.

[21] *See Sagebrush, a California Partnership*, 130 FERC ¶ 61,093, *order on reh'g*, 132 FERC ¶ 61,234 (2010).

[22] 42 U.S.C. § 16451, *et seq*.