

**PRELIMINARY SURVEY OF
FERC RENEWABLE ELECTRICITY REGULATORY INITIATIVES**

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Improving the design, operation and overall capacity of the U.S. electric power system to accommodate large-scale integration of renewable electric generators will require us to re-engineer both the operation of the grid and the Federal regulatory framework. This paper reviews regulatory issues that the Federal Energy Regulatory Commission (FERC) is currently addressing that will impact the integration of renewable electricity into the bulk power system and outlines how these issues may be relevant to the RenewElec Project's work. These issues include:

- Modifications to FERC's *pro forma* Open Access Transmission Tariff (OATT) to accommodate variable and intermittent renewable generation, including ancillary services and wind (and solar) following services;
- Revising rules applicable to energy, capacity and ancillary services markets in centralized power markets;
- Transmission planning, siting, cost allocation, and rate incentives;
- Demand response, energy storage, and electric vehicle policies;
- Interconnection procedures and agreements for renewable generators;
- NERC reliability standards; and
- Coordination of data availability and transmission operation between balancing authorities.

I. The FERC Regulatory Framework

FERC has wide-ranging authority over wholesale power markets and the bulk power system. Its exercise of that authority is critical to the deployment of variable and intermittent renewable generation. These FERC authorities encompass the following:

A. Interstate Transmission and Wholesale Sales Services.—FERC regulates rates, terms and conditions of service for transmission and wholesale sales of electricity in interstate commerce. This authority extends not only to transmission and wholesale sales between points in different states but also transmission and wholesale sales of electricity within a state that use the interconnected transmission grid, except for electric energy generated and transmitted wholly within the Electric Reliability Council of Texas (ERCOT). Under this authority, FERC exercises comprehensive regulatory jurisdiction over regional transmission organizations (RTOs), which provide transmission service and operate energy and capacity markets in about half of the United States. FERC does not regulate the “bundled” sale of electric energy and delivery service to serve a utility’s native load, nor does it regulate retail sales or local distribution services.

B. Reliability.—FERC supervises the North American Electric Reliability Corporation (NERC) and regional reliability councils, which set mandatory reliability standards for the bulk power system.

C. Siting and Planning.—FERC has limited backup siting authority for interstate transmission facilities. It also has responsibility with respect to planning and providing rate incentives for expansion of transmission facilities. It has no authority over siting of generation, except for hydroelectric projects.

D. Small Renewables.—Under section 210 of the Public Utility Regulatory Policies Act (PURPA), FERC has exempted renewable generators from most state and Federal utility regulation and required utilities outside of RTOs to purchase the output of small and mid-size renewable facilities at the utilities’ avoided cost.

II. Current FERC Regulatory Proceedings

The FERC regulatory framework is particularly relevant to the development of renewables because almost all renewable electricity generated outside ERCOT uses interstate transmission facilities and much of it is sold into wholesale markets—both of which are regulated by FERC. FERC has undertaken a number of regulatory initiatives that may improve economic and physical access to transmission services and wholesale markets for renewable generators and their customers. While some of these initiatives are at an exploratory stage (e.g. Notice of Inquiry or Request for Comment), ultimately many of them will have binding effect on transmission providers and operators, as well as renewable generators. As the RenewElec Project proceeds with its analysis and recommendations, it may wish to comment or otherwise participate in these proceedings.

A. INTEGRATION OF VARIABLE ENERGY RESOURCES

On January 21, 2010, FERC published a Notice of Inquiry¹ that takes a “fresh look” at federal transmission policies and practices that bear on integration of what FERC denominates as “variable energy resources” (VERs) in RTO and non-RTO balancing areas around the country.² FERC’s stated goal was to identify market and operational reforms that could remove “unnecessary barriers to transmission service and wholesale markets” for VERs (and other technologies that may aid their integration).³ Whether and how FERC will implement any findings based on the studies and data provided, e.g. through rulemakings to modify the *pro forma* Open Access Transmission Tariff (OATT) or by directing NERC to issue or modify reliability standards, remains to be seen. Reports and recommendations being developed by NERC’s Integrating Variable Generation Task Force—a working group of about 80 members from utilities, ISOs/RTOs, wind and solar companies, associations and government formed in 2007 by NERC’s Planning and Operations Committees to address reliability issues associated with large-scale VER integration into the bulk power system—may be influenced by the information submitted to FERC as well (see below, II.F for more on NERC).⁴

FERC received 147 comments on the following seven topics related to the impacts of VER integration. Notable issues raised by FERC and commenters on each of these seven topics are discussed below. RenewElec may wish to provide input on many of these issues should FERC eventually decide to undertake a rulemaking:

- 1. Data and Reporting Requirements.** FERC inquired as to whether it should modify the specifications in existing requirements for provision of operational data to better predict the generation output of intermittent energy resources like wind and solar, and if so, what level of data-sharing is necessary, when coupled with advanced communication and metering tools, to ensure reliable and efficient VER integration. NERC, Xcel Energy and others commented that system operators would benefit from integrating near-term (3-6 hours) forecasting products into their software and system to better anticipate ramping needs. They noted that shorter term data (0-3 hours) is unavailable with current technology.

- 2. Scheduling Practices and Incentives.** Recognizing that RTOs/ISOs often schedule external resources on an hourly basis to ensure consistency with scheduling practices in non-RTO/ISO regions without real-time markets, FERC sought to explore whether and how greater scheduling flexibility could facilitate efficient and reliable integration of VERs. FERC also inquired about the intermittent resource imbalance penalty exemption in FERC’s current *pro forma* OATT. At present, an “intermittent resource”—defined as an electric generator that is “not dispatchable and cannot store its fuel source” (i.e. wind and solar generators)—is not subject to the most stringent “third tier” imbalance penalties for deviations greater than 7.5 percent of scheduled amounts; any deviations over 1.5 percent or 2 MW (whichever is larger) are only penalized with a required payment of 110 percent of the incremental or 90 percent of the decremental cost of providing the imbalance energy.⁵ Many comments focused on how to more accurately and efficiently employ sub-hourly generator scheduling and dispatch, thereby decreasing reliance on costly reserve products.
- 3. Forward Market Structure (Day Ahead) and Reliability Commitment Processes.** FERC sought to explore the tendency of VERs to self-schedule the majority of their supply in real-time energy markets rather than participate in day-ahead markets, and whether this may result in costly out-of-market commitments and uplift costs. Many comments addressed whether a shorter unit commitment period (e.g. half hour periods for day-ahead markets) in both organized markets and other balancing areas could decrease unnecessary system uplift costs.
- 4. Balancing Authority Area Coordination, Expansion and/or Consolidation.** FERC solicited comments on issues including (i) whether smaller balancing authorities (BA) have higher VER integration costs than larger BAs, (ii) whether FERC should encourage consolidation of BAs, (iii) what alternative arrangements are available to reduce barriers to operational coordination between BAs, and (iv) what the costs and benefits are for smaller, generation-only balancing authorities.

 - *Potential RenewElec input:* Assess the costs and benefits of creating a large area “virtual balancing authority” designed to accommodate VERs across a region; assess the usefulness and potential cost savings of interregional wind and solar forecast data exchanges between existing balancing authorities to facilitate VER integration.
- 5. Reserve Products and Ancillary Services.** Several comments emphasized the need for “flexibility reserves” capable of providing ramping capability better tailored to variable outputs than traditional contingency reserves.⁶

 - *Potential RenewElec input:* Assess barriers and solutions to development of wind-following and solar-following ancillary services.
- 6. Capacity Markets.** FERC inquired as to whether capacity rating rules, eligibility requirements to bid into day-ahead markets, and the inability of capacity markets to accommodate ramping needs discriminate against VERs.

 - *Potential RenewElec input:* Assess whether capacity rating rules should be tailored to specific time periods to accommodate the varying peak capacities of different types of renewable generation and thus better position renewable generation for participation in the capacity markets.

7. **Redispatch and Curtailment Practices.** FERC inquired as to whether VERs are curtailed too frequently in response to transmission congestion, minimum generation events, and ramping events, because of a lack of clarity in curtailment protocols, and whether the current practices and protocols thereby result in unnecessary costs, and, consequently, unjust and unreasonable rates.

➤ *Potential RenewElec input:* Assess effectiveness of various technologies (e.g. set point control systems) for minimizing curtailment of VERs.

B. TRANSMISSION PLANNING AND COST ALLOCATION

On June 17, 2010 FERC issued a Notice of Proposed Rulemaking on *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*.⁷ The initial comment period closed on September 29, 2010; reply comments are due by November 12, 2010. Under the proposed rule, transmission providers would be required to amend their OATTs (or safe harbor tariffs for public power utilities) to reflect new FERC requirements, including:

1. Expanding the scope of the **region-wide transmission plan** required under FERC Order 890 to explicitly consider public policy requirements (e.g. state renewable portfolio standards).
2. **Elimination of incumbent transmission owners rights of first refusal** relative to independent transmission developers, for constructing and owning new projects selected for inclusion in a regional transmission plan. Among other things, this would be intended to stimulate more investment in merchant transmission projects designed to bring remote, location-constrained renewables to load centers, such as the Zephyr and Chinook high-voltage direct current transmission projects being developed by TransCanada to connect the wind resources of Montana and Wyoming to load in southern California, Arizona and Nevada.
3. **Interregional transmission planning agreements** between neighboring transmission planning regions to set out standardized criteria/methodologies for planning interregional transmission facilities and thus enhance the prospects of high voltage, renewables-oriented transmission development between regional transmission systems.
4. **Standardized cost allocation methodologies** for both intraregional and inter regional transmission projects that adhere to FERC's cost allocation principles and may allow for separate allocations of transmission facility costs based on the benefits provided—whether to maintain reliability, relieve congestion or achieve “public policy” requirements.⁸

While this rulemaking is not focused explicitly on promoting renewable generation, FERC's ultimate action in this proceeding may have important implications for renewables. A final rule incorporating the principal features of the proposed rule should provide more opportunities for “meaningful input” from renewable electricity generators and other stakeholders in transmission planning and require transmission providers to more explicitly address renewable (and efficiency) energy policy priorities in the planning process. One anticipated result might be to enhance the attractiveness to investors of transmission projects designed to provide access for location-constrained renewables.

C. DEMAND RESPONSE.

Demand response can play a valuable complementary role in expanding penetration of wind and solar power. It can provide operational flexibility to maintain reliability during sharp down-ramps in wind or solar generation. Communications technologies have improved the dispatchability of demand response resources to make load reductions available to operators in a matter of minutes in many cases.⁹ Large-scale deployment of demand response products in wholesale energy markets has been impeded by a lack of (i) consistent metrics for evaluating the performance of various wholesale demand response products, (ii) standardization of how demand response as a generation resource is priced, and (iii) coordination with retail/distribution markets. FERC is currently addressing these impediments.

1. Performance Evaluation of Demand Response

On April 15, 2010, FERC amended its regulations to incorporate by reference new business practice standards and communication protocols for public utilities regarding demand response.¹⁰ FERC adopted 40 definitions related to “basic product categories” in wholesale demand response markets (i.e. energy, capacity, reserve and regulation services), which identify the measurement and verification characteristics of these wholesale products and services (e.g. reduction deadlines, advance notification instructions, and telemetry accuracy). By standardizing standards and protocols for demand response performance evaluation in wholesale markets, this final rulemaking was intended to facilitate the ability of demand response providers to participate in electricity markets, and expand opportunities for load serving entities and other customers to utilize demand response energy, capacity, reserve and regulation products, especially customers that operate in more than one organized power market.¹¹ FERC’s adoption of demand response communication protocols could lead to a more stable pricing scheme and greater market accessibility for demand response products, which could, in turn, facilitate better integration of variable renewable energy resources. However, continued state jurisdiction over retail utility’s demand response programs, meters and infrastructure will affect the pace and nature of such progress.

2. Pricing Demand Response

In March 2010, FERC proposed to amend its regulations to establish a demand response pricing regime for ISOs and RTOs with tariff provisions that permit demand response providers to act as generation resources by bidding into day-ahead and real-time markets. If finalized in its present form, the rule would require these ISOs and RTOs to pay to demand response providers, in all hours, the locational marginal price for the amount of energy reduction “produced” by demand response providers.¹² A technical conference was held on September 13, 2010 (comment period closed on October 13, 2010) to explore issues raised by commenters as to the appropriate price to be paid, whether the benefits of demand response compensation at full LMP outweigh the cost of paying for these resources and how the cost of the proposed compensation level—locational marginal price at all hours—should be allocated within the ISO or RTO footprint.¹³ The outcome of this proceeding could encourage greater participation in demand response programs within organized ISO/RTO markets that, in turn, could assist ISOs and RTOs in accommodating variable wind and solar generation.

D. ELECTRIC STORAGE TECHNOLOGIES

Electric storage technologies, such as batteries, flywheels and the use of molten salt with concentrating solar thermal plants, can help address the intermittency of wind and solar generation, integrate renewables more smoothly into the grid, and store renewable energy for sale at peak hours. Depending on its application, electric storage can act as a generation resource, an ancillary service for transmission, or a distribution asset. Approved methods of rate recovery, accounting and financial reporting exist for each of these asset categories; but the same is not true for electric storage because it spans all three.¹⁴

On June 25, 2010, FERC's Office of Energy Policy and Innovation issued a *Request for Comments Regarding Rates, Accounting and Financial Reporting for New Electric Storage Technologies* (comment period closed on July 30, 2010).¹⁵ The purpose of the staff request is to lay a foundation for categorizing electric storage service costs for rate purposes. This request will also generate feedback and staff deliberation on the appropriateness of various FERC rate rules and policies in the unique context of electric storage.¹⁶ Clear rules in this area may facilitate greater penetration of renewables by growing the market for ancillary electric storage services and other services that complement the variable nature of wind and solar generation.

E. RENEWABLE INTEGRATION UNDER THE CURRENT OATT

1. Ancillary Service Requirements Related to Renewable Generation

FERC has approved OATT amendments submitted by a few individual transmission providers to establish charges for “wind following” services, such as generator imbalance.¹⁷ However, these FERC orders did not establish a standard methodology or clear precedent for how the cost of such services should be determined in all cases. FERC recently rejected a proposed “proxy generator” approach to calculating the cost of service for wind following services.¹⁸ Transmission providers have framed the costs of providing such services as a function of the intermittency of wind alone, but the provision and pricing of load-following and regulation services could also be considered more comprehensively to better reflect the diversity among all types of generation and load profiles in the balancing area.

2. Interconnection Procedures and Agreements

FERC requires all public utilities within its jurisdiction under the Federal Power Act (i.e. utilities other than federal and state public agencies and cooperatives) that own, control, or operate facilities for transmitting electric energy in interstate commerce to include in their OATTs standard procedures and agreements for interconnecting large generators (20 MW or greater)(LGIP) and small generators (SGIP), respectively. In 2005, FERC adopted special interconnection standards for wind generators to accommodate “the unique design and operating characteristics of wind plants, their increasing size and increasing level of penetration on some transmission systems (in terms of the wind generating capacity's percentage contribution to total system generating capacity), and the effects they have on the transmission system.”¹⁹ Among other exceptions to its *pro forma* large generator interconnection procedures (LGIP), FERC exempts large wind generators from the power factor design criteria requirement, because FERC determined it would be difficult for non-synchronous generators, such as wind generators, to maintain the power factor required in the *pro forma* LGIP. FERC also requires a case-by-case approach to determining whether wind generators must maintain reactive power capabilities—the Transmission Provider has the burden of demonstrating the need for such capabilities so that a “Transmission Provider does not require a wind plant to install costly equipment that is not needed for grid safety or reliability.”²⁰ FERC also requires large wind generators to implement certain reliability-related accommodations, such as mandatory low voltage ride-through

capabilities so that wind plants can remain on line (and avoid being automatically tripped off) during voltage disturbances.²¹

FERC staff is also currently reviewing interconnection issues associated with “alternative technologies including the use of non-synchronous generators and other alternative technologies that respond differently to grid disturbances and may have different effects on the grid than large, synchronous generators.”²² No amendments to current interconnection procedures and agreements have been proposed at this time.

F. NERC RELIABILITY STANDARDS

Under the Federal Power Act, NERC develops and enforces reliability standards for the bulk-power system, subject to FERC approval. FERC has authority to direct NERC to develop new or modified reliability standards, and to ensure NERC’s compliance with those directives.²³ According to NERC’s *2009 Long-Term Reliability Assessment*, 260,000 MW of new renewable nameplate capacity is forecasted to come online in the next ten years. Ninety-six percent of this capacity is expected to be comprised of wind (229,000 MW) and solar (20,000 MW), but only 38,000 MW of wind and 17,000 MW of solar are projected to be available at times of peak demand. Because so much new renewable capacity is projected to be “energy dominant” (resources predominantly available during off-peak hours), NERC asserts that “significant changes” to traditional planning and operating techniques will be required to ensure reliability.²⁴ How NERC implements these changes will have significant influence on long term prospects for renewables.

III. Conclusion

FERC is playing a critical role in shaping the capacity and accessibility of the nation’s bulk power system and wholesale electricity markets to accommodate large-scale integration of renewable electricity generation in the months and years to come. Some FERC regulatory initiatives will indirectly impact renewables, such as electric storage and demand response pricing, while other initiatives expressly focus on integration of variable renewable resources. As RenewElec develops its recommendations, the Project should take advantage of opportunities to apprise FERC of its recommendations by commenting in ongoing proceedings or by briefing Commission staff.

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ENDNOTES

¹ *Integration of Variable Energy Resources*, 75 Fed. Reg. 4316 (Jan. 27, 2010), 130 FERC ¶ 61,053 (2010) (comment period closed in March 2010).

² Other wind integration studies are currently being conducted by the New England and New York ISOs, WestConnect’s *Virtual Control Area Work Group*, and the Western Electricity Coordinating Council, which is developing a congestion and balancing toolkit.

³ *Integration of Variable Energy Resources* at P 9.

⁴ NERC's Integrating Variable Generation Task Force (IVGTF) first report on accommodating high levels of variable energy generation into the bulk power system was published in 2009 (http://www.nerc.com/docs/pc/ivgtf/IVGTF_Report_041609.pdf). Various subcommittees within IVGTF are now developing "follow on" reports that will include recommendations for NERC. A 2009-2011 "work plan" lays out the issues currently being studied by various subcommittees within the Task Force (http://www.nerc.com/docs/pc/ivgtf/IVGTF_Work_%20Plan_111309.pdf).

⁵ *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007), P 665-6.

⁶ Methods for calculating reserves have evolved, and according to the National Renewable Energy Laboratory, some of the most recent work can be found in its January 2010 Eastern Wind Integration and Transmission Study (<http://www.nrel.gov/wind/systemsintegration/ewits.html>) and its May 2010 Western Wind and Solar Integration Study (<http://www.nrel.gov/wind/systemsintegration/wwsis.html>).

⁷ *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 75 Fed. Reg. 37,884 (Jun. 20, 2010), 131 FERC ¶ 61,253 (2010).

⁸ FERC's proposal raised the issue as to whether cost allocation methodologies should be standardized on a regional or interregional basis. The proposed rule would establish standard cost allocation principles for RTOs, ISOs, and planning regions to follow when establishing regional cost allocation methodologies: (1) allocate costs in a manner that is at least "roughly commensurate" with estimated benefits; (2) do not involuntarily impose costs on entities that receive no benefits from transmission facilities; (3) do not preclude projects with significant net benefits from being included in a regional transmission plan; (4) do not involuntarily allocate costs for transmission facilities outside of the planning region in which the facilities are located; (5) provide stakeholders with transparent access to cost allocation methods and data requirements; and (6) allow the use of different cost allocation methods for different types of transmission facilities.

⁹ While demand response is increasingly being classified as a non-spinning reserve and used as an ancillary service by many utilities to accommodate variability, the average displacement by demand response of generation (e.g. thermal or hydroelectric) deployed as operating reserves and/or regulation is less than 1% nationwide. NERC, *Key Issues: Demand Response* (<http://www.nerc.com/page.php?cid=4|53|56>).

¹⁰ *Standards for Business Practices and Communication Protocols for Public Utilities Regarding Demand Response*, 75 Fed. Reg. 20,901 (Apr. 22, 2010), FERC Stats. & Regs. ¶ 31,309 (2010).

¹¹ These standards and protocols were developed by the Wholesale Electric Quadrant of the North American Energy Standards Board (NAESB) to categorize various demand response products and service and to support the measurement and verification of these products and services in wholesale electric energy markets. NAESB work groups have been meeting throughout 2010 to improve these standards and protocols, in conjunction with Demand Response Matrix developed by the ISO/RTO Council, and are also developing business practice standards to measure and verify energy reductions that are made to comply with a renewable portfolio standard that includes energy efficiency or a stand-alone energy efficiency portfolio standard. Schedules,

agenda and related materials for the NAESB Demand Side Management and Energy Efficiency group are available online (<http://www.naesb.org/dsm-ee.asp>).

¹² *Demand Response Compensation in Organized Wholesale Energy Markets*, 130 FERC ¶ 61,213 (Mar. 18, 2010).

¹³ *Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference on Demand Response Compensation in Organized Wholesale Energy Markets*, 132 FERC ¶ 61,094 (Aug. 2, 2010).

¹⁴ Where as older pumped storage hydropower units were generally built at retail ratepayers expense at a time when load-serving utilities were vertically integrated, new methods of cost recovery are currently being considered, ranging from a traditional cost-of-service approach to a multiple revenue stream approach that blends cost-of-service recovery with other market-based costs that capture the risk of wholesale market transactions.

¹⁵ *Request for Comments Regarding Rates, Accounting and Financial Reporting for New Electric Storage Technologies*, 75 Fed. Reg. 36,381 (Jun. 25, 2010).

¹⁶ FERC staff notes, for example, that the current prohibition on third-party provision of ancillary services at market-based rates to transmission providers, known at the “Avista Policy” “may pose an undue barrier” to development of electric storage as an ancillary service.

¹⁷ *Westar Energy, Inc.*, 130 FERC ¶ 61,215 (2010); *NorthWestern Corporation*, 129 FERC ¶ 61,116 (2009); *Entergy Services, Inc.*, 120 FERC ¶ 61,042 (2007).

¹⁸ *Puget Sound Energy Inc.*, 132 FERC ¶ 61,128 (2010).

¹⁹ *Interconnection for Wind Energy*, Order No. 661-A, 113 FERC ¶ 61,254, P 11 (Dec. 12, 2005).

²⁰ *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 68 Fed. Reg. 49,845 (Aug. 19, 2003), *order on reh'g*, Order No. 2003-A, 69 Fed. Reg. 15,932 (Mar. 26, 2004), FERC Stats. & Regs. ¶ 31,160, P 407 n.85 (2004).

²¹ *Interconnection for Wind Energy*, Order No. 661, 111 FERC ¶ 61,353 (Jun. 2, 2005), *order on reh'g and clarification*, Order No. 661-A, 113 FERC ¶ 61,254 (Dec. 12, 2005).

²² FERC Website, *Standard Interconnection Agreements for Wind Energy and Other Alternative Technologies* (<http://www.ferc.gov/industries/electric/indus-act/gi/wind.asp>).

²³ *North American Electric Reliability Corporation*, 130 FERC ¶ 61,203 (Mar. 18, 2010) (requiring NERC to amend its voting procedures to promote standards that are responsive to FERC directives).

²⁴ *North American Electric Reliability Corporation, 2009 Long-Term Reliability Assessment, 2009-2018* (Oct. 2009) (http://www.nerc.com/files/2009_LTRA.pdf).