

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

Interconnection Queuing Practices	)	Dockets No.	AD08-2
Midwest Independent Transmission System Operator, Inc.	)		ER07-1375
Midwest Independent Transmission System Operator, Inc.	)		ER07-970
Southwest Power Pool, Inc	)		ER07-1311
PacifiCorp	)		OA07-54
Bonneville Power Administration	)		NJ08-2-000
PJM Interconnection, L.L.C.	)		ER08-280-000
California Independent System Operator Corporation	)		ER08-140-000

**COMMENTS OF THE AMERICAN WIND ENERGY ASSOCIATION**

January 10, 2008

Pursuant to the Notice Inviting Comments issued December 17 in the above-referenced dockets, the American Wind Energy Association (“AWEA”) submits the following comments.

**I. COMMUNICATIONS**

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## **II. DESCRIPTION OF AWEA**

AWEA is a national trade association representing over 1200 entities with a common interest in encouraging the expansion and facilitation of wind energy resources in the United States. AWEA members include wind turbine manufacturers, component suppliers, project developers, project owners and operators, financiers, researchers, renewable energy supporters, utilities, marketers, customers and their advocates. Many AWEA members are attempting to develop projects that are in interconnection queues in the Midwest, West, and Northeastern regions of the country.

## **III. INTRODUCTION AND SUMMARY**

AWEA wishes to thank FERC Commissioners and staff for their leadership role in overseeing changes needed to integrate newer technologies into the electric system. In FERC Orders No. 661 and 661-A (Interconnection for Wind Energy), Order No. 890, and related orders in individual company proceedings, the Commission has recognized that the rules and procedures of the electric industry were designed with different technologies in mind and that the industry's new technology choices in some cases require significant updating of such rules and procedures. These changes are similar in character to the changes that were required when nuclear, coal, and gas generation technologies were new to the system decades ago. A truly non-discriminatory and level playing field will require further evolution; right now, interconnection queues should be the main focus of such reform. This proceeding is an important vehicle for that purpose.

FERC, states, utilities, and generators must now acknowledge that the interconnection queue process is being relied upon to do much more than it is capable of. The generator-by-generator process is being relied upon to address the multiple transmission planning needs of the regional network through determination of network upgrades required by each incremental generator in the queue and by assigning those costs of shared facilities to individual projects. This process is unnecessary and is a major source of queue gridlock.

AWEA believes FERC and Transmission Providers should preserve the significant progress made by FERC's Order No. 2003 which standardized interconnection, facilitated competitive entry, and provided a meaningful set of rights and obligations for transmission providers and customers. This process should be viewed as an evolution based largely on the fact that there is a different portfolio of generation in today's queues than there was at the time Order No. 2003 was developed, not a fault of Order No. 2003. We urge the Commission to avoid steps that might harm open access and bring back risks of discrimination.

Although the problem is largely occurring in RTO/ISO areas, AWEA wishes to re-iterate its strong support for RTO/ISO market structures. Such markets can integrate far more wind energy than the balkanized system in place in the rest of the country. In fact strengthening RTOs and ISOs in their ability to plan and perform other functions would help alleviate the problem. With that context, AWEA wishes to make the following general recommendations:

- Short-term queue improvements should be made as soon as possible; MISO and CAISO proposals should be filed in the spring and approved by summer.

- Solutions should be region-specific (ie, developed for each ISO or RTO) but driven through active FERC and state oversight towards best-practices that achieve open access and just and reasonable rates rather than the politics in stakeholder committees.
- Within a year the interconnection process should be reformed to one that:
  - Focuses interconnection solely on localized system impacts for either energy or capacity resources;
  - Leaves most network upgrade needs to the regional transmission planning process, which along with cost allocation policies, needs to be reformed to lead to actual transmission development;
  - Opens opportunities and encourages transmission developers to propose projects connecting areas with many generation projects in the queue.

#### **IV. THE PROBLEM**

There are large backlogs of interconnection requests around the country. From the wind industry's perspective, many companies are extremely frustrated that the obligations on transmission providers are not being upheld. Studies are being delayed, results in terms of cost assignment are hard to predict, unreasonable requirements are sometimes placed on generators, and solvable problems are not being solved in a timely way. The result is that many good projects are unreasonably delayed, harming wind development nationally and harming many states' ability to meet renewable energy goals.

#### **V. ASSIGNING NETWORK UPGRADE COSTS ARE THE MAIN ROOT CAUSE OF THE PROBLEM**

It is instructive that queues are in better condition in ERCOT, Wisconsin, Michigan, and non-ISO/RTO regions than in CAISO, most of MISO, SPP, PJM, NYISO, and ISO-NE. Why? Because the former areas do not use "participant funding" where network upgrade costs are paid by the generator. In the latter areas, participant funding is the root cause of most of the queue problems. Participant funding creates a situation where a typical 100 MW, \$200 million wind project might face a network upgrade charge of \$0 to \$30 million with little basis for knowing where in that large range the price tag might fall. Even in California where network upgrade costs are credited back to generators in their transmission service, the outcome makes a difference for generators and the issue adds tremendous complexity and transactions costs to the interconnection process. In response to unknowable and potentially very high network upgrade costs, a rational generator may submit more project requests than they intend to complete. If the cost comes out high, they can cancel or suspend the project. This in turn causes more projects to enter the queue, and then the cycle reinforces itself. There are promising short term solutions to improve the current situation but the problem will never be fully solved until this root cause of the problem is addressed.

Fundamentally, the interconnection queue process cannot shoulder the burden of regional network transmission planning. This is especially true given the sequential one-at-a-time process that is used. It results in one generator picking up the tab for a large shared facility that has many other benefits including meeting load growth, reducing congestion, and increasing reliability. The interconnection queue process cannot cure cancer and it cannot be relied upon to

address all of the needs of the grid. WE can look to ERCOT, Wisconsin, and Michigan for models of how the interconnection process can be simplified by keeping regional network planning and cost allocation separate from the interconnection process.

Participant funding was allowed by FERC in Order No. 2003 in areas that have ISOs or RTOs because the process of assigning costs could be trusted to be executed fairly by these independent entities. FERC's determination that participant funding would be allowable under the Federal Power Act in RTO/ISO areas, however, does not mean that participant funding is superior to other approaches or is even workable in today's environment. It is time for FERC, states, and regions to revisit this policy. States must be involved in this discussion because the current policy is such a barrier to achieving so many states' objectives and because states have so much influence over cost recovery and over their utilities' RTO/ISO participation.

## **VI. PROPOSED SOLUTIONS**

A suite of short, medium, and long term solutions are required for each region experiencing queue logjams. RTOs like MISO with particularly acute problems should implement short term solutions as soon as possible. Some may require retro-active changes in the queue process similar to the one AWEA supported in the NYISO (114 FERC ¶ 61,207, Docket No. ER 06-558-000). The solutions can vary by region because the queue process is tightly integrated with each region's particular structure with regard to transmission service, transmission planning, cost allocation, and capacity markets. Short term solutions can allow interconnection within the next year without change to infrastructure or tariffs. Longer term solutions may require more change to tariffs and/or infrastructure.

### **A. Address the root cause through cost allocation reform**

The solution is simple. ATC (Wisconsin) and ITC (Michigan) recently made short filings to FERC relieving generators of the obligation to pay for network upgrades and now projects are moving forward in those areas. ERCOT has never charged generators for network upgrades. There is no reason why the rest of the country could not follow suit. There is a broader need to reform all regional and sub-regional cost allocation policies in order to promote transmission.

### **B. Regional planning and cost allocation**

The grid's needs should be addressed in a process that considers the impacts of not one generator at a time and not just generator interconnections in the aggregate, but also load growth, reliability needs, and economic congestion reduction. That is the regional planning and cost allocation process. Transmission network needs should not be addressed through the interconnection process. Information from the queues, in terms of Megawatts of financially committed generation in different areas should feed into the regional transmission plan.

### **C. Clusters**

The use of well-conceived geographically based clusters should be expanded to accelerate processing and efficiently share transmission upgrades. To sound one note of caution, poorly organized clusters can worsen the problem so this must be done carefully. The clusters should include only generation that impacts common facilities in order to capture the economies of scale in transmission upgrades without creating high risk of projects dropping out and causing a need for re-studies. The clusters should be small. To ensure that cluster studies do not fail due to projects dropping out, they should include provisions to ensure generators' commitment to participate. The process could be similar to an open season, or could be combined with an open season for transmission service.

Tariffs currently allow for clustering. However, there may be a need for changes to the tariff to improve the selection of rational clusters and to prevent failure due to project churn.

#### **D. Conditional and energy-only interconnection service**

The interconnection process can be accelerated in the very near term for generators willing to be curtailed. Currently energy-only service is included in the tariff but is not widely offered. A new service for interconnection that is similar to the Conditional Firm transmission service in FERC Order No. 890 could be added to tariffs to apply to interconnection service. The concept is the same: the generation would be willing to be curtailed in certain defined system conditions or time periods. [Order No. 890 ¶ 911, 912 Paragraphs 958 and 1064] Customers should be allowed to take an active role in identifying system impacts by working with the Transmission Provider and using its base case, to make its own assessment of the risks of certain system conditions. FERC will need to require more transparency to facilitate this agreement between the customer and transmission provider. The conditions that merit curtailment should be defined in the Interconnection Agreement. This service would require a tariff change.

#### **E. Accelerate process for committed projects**

The tariff should increase the ability of strongly committed projects to move through queues. Customers can make demonstrations of their commitment through milestones (land control, turbine supply, easements for generator tie lines) and financial commitment (posting security or cash). There are limits to the financial burden that should be imposed before it becomes a barrier to entry, but the current fee that is \$10,000 in some ISO/RTOs is well below the level at which this burden becomes too great. Adding milestones or financial commitment may require changes to tariffs.

#### **F. Change modeling methodology**

System models should include a realistic amount of operating wind. The current method of assuming all wind is operating at full capacity all the time overstates system impacts and is not a credible "worst case." Also, modeling only peak load hour conditions does not give an accurate picture of the output or transmission needs of wind projects. System models should also include a realistic amount of higher queued projects. Communication between the utilities issuing RFPs and the Transmission Provider is one way to better estimate a realistic amount of generation to expect. Tariff changes would not be required to make such improvements.

## **G. More resources**

Transmission Provider processing capability should be increased through greater resources and greater utilization of customer-provided studies and information. In some cases in the past, a shortage of RTO/ISO staff has been a problem that has been remedied by this relatively easy step. No tariff change is required to accomplish this.

## **H. Transmission project proposals**

Transmission developers, providers, owners, and operators should develop transmission project proposals based on queue project locations. Transmission owners and developers should view transmission more as an opportunity than a threat. Stand-alone transmission companies are outperforming vertically integrated companies in this area, so that corporate structure should be actively promoted by FERC and states.

## **I. Pro-active transmission**

The use of pro-active transmission policies to connect location-constrained resources should be expanded to access areas with significant resources that would require shared high voltage transmission. Recently FERC issued a declaratory order on a California ISO proposal to do this (119 FERC ¶ 61,061, Docket No. EL 07-33). On a state level, Texas, California, Minnesota, and Colorado are doing similar pro-active transmission planning and financing. Financing in this approach is done mainly by current transmission customers but also in part through financial commitments from generation project owners in return for rights for interconnection and service. The approach can take place at a small scale where two or three projects wish to use a shared generator tie line, or a large scale for thousands of Megawatts. The appendix to these comments includes a summary of these policies around the country. The approach requires tariff changes and new infrastructure development and is therefore a longer term solution. However, the process needs to start now to meet needs a few years in the future.

# **VII. WHO CAN HELP AND HOW**

Many parties have a role in improving this process. The fact that we are presenting these views to FERC should not imply that we are asking FERC to unilaterally mandate all of these changes nationwide. To clarify, these are the actions we are requesting.

## **A. FERC**

FERC has an important role to play in leading reform, encouraging innovation, monitoring progress closely through staff participation in ISO/RTO stakeholder committee meetings, and interacting closely with states. WE urge FERC to continue its active role, and to avoid accepting proposals from RTO/ISOs that satisfy only stakeholder politics and do not solve the problem.

## **B. States**

States can lead by encouraging ISO/RTOs to solve this problem that is a barrier to achieving their objectives and helping to move away from participant funding. States can help in particular by influencing ISO/RTO cost allocation decisions through Regional State Committees.

### **C. Transmission owners**

We would like to see transmission owners and developers follow the lead of companies like ATC and ITC to start proposing projects and identifying opportunities to increase reliability, reduce congestion, and integrate renewable energy.

### **D. Wind industry**

For our part, the wind industry is open to suggestions on how to make the queue process work better for everyone. We will participate in ISO/RTO stakeholder meetings through our member companies and regional and national organizations. We will consider changes to the flexibility provided in the interconnection process, the milestones, and financial commitments required to ensure that the queues are filled with committed projects ready to move forward.

## **VII. CONCLUSION**

WHEREFORE, AWEA submits these comments for the Commission's consideration in this docket.

Respectfully submitted,

AMERICAN WIND ENERGY ASSOCIATION

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**APPENDIX: Pro-active transmission proposals and policies to develop transmission accessing renewable energy.**

This table summarizes and compares pro-active transmission proposals and policies that are being considered around the country. A primary driver for these policies is state renewable portfolio standards that, in turn, are driving demand for new renewable energy facilities, particularly wind projects. The table was compiled reviewing available documents and is current as of the end of December 2007.

	<b>California ISO Location Constrained Resource Interconnection (LCRI)</b>	<b>Texas Competitive Renewable Energy Zones (CREZ)</b>	<b>Colorado Energy Resource Zones (CERZ)</b>	<b>Bonneville Power Administration Commercial Infrastructure Policy</b>	<b>MISO Regionally Planned Generator Interconnection Project</b>	<b>California PUC Transmission “Back Stop”</b>
Description	Cost recovery assurance via transmission rates for connecting remote resources to the grid through non-network upgrades.	Designates zones with high, substantiated renewable energy development interest and authorizes a specific transmission plan necessary to deliver a specified MW level of renewable energy development.	Designates zones with high clean energy potential and transmission necessary to access it.	For qualified transmission projects, replaces participant funding with rolled-in transmission rates for transmission projects that generate certain levels of new revenue. Takes into account reliability and economic benefits.	New transmission to interconnect for multiple generators in a location constrained area, sized to meet current and future need for transmission capacity.	Cost recovery assurance to transmission owners that volunteer to finance gen-tie or transmission facilities that facilitate achievement of the California RPS.

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Eligibility/Process	Non-network facilities that would connect at least two eligible and unaffiliated generators in designated energy resource areas. The non-network facilities must go through the CAISO Transmission Planning Process and turned over to the CAISO’s operational control once in operation.	Zones determined by availability of renewable energy resources, suitability of land and financial commitment of generators to construct renewable capacity. Transmission plan based on cost of transmission, estimated costs of ancillary services, and benefits of renewable energy development.	By October of every odd-numbered year, each Colorado utility required to submit designated energy resource zones; transmission plans to access the zones; and permit applications for new or expanded transmission. Colorado PUC required to act within 180 days.	Facilities needed to serve requests in BPA’s transmission service queue. Does not apply to generator interconnections or to the California and Montana Interties. Under discussion as to whether BPA will provide flexibility on point of delivery or not.	Non-network transmission facility that is not a reliability project; turned over to MISO’s operational control; and be part of MISO’s transmission plan	Applies to in state bulk transmission facilities (network or gen-tie) serving multiple RPS generators. Gen-tie facilities must have at least one CPUC-approved RPS contract. Must show facilities necessary to meet RPS and normal cost recovery methods unavailable.

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Cost recovery	Costs are rolled into the CAISO’s transmission access charge until generators come on-line, after which generators pay pro rata share of going forward costs.	Other than the costs of direct interconnection facilities, transmission costs are spread across all load-serving entities in ERCOT. Annual proceeding available to incorporate capital costs of new transmission facilities.	Subject to annual adjustment, utilities may recover planning, development, and construction costs for permitted transmission facilities via a rate adjustment clause. Construction work in progress costs can also be recovered at the weighted average cost of capital, including a return on equity.	BPA currently uses participant funding for new transmission. In addition to new transmission revenues, BPA proposal would estimate expected reliability, economic and “future use” benefits of new transmission in BPA transmission rates and recover those in BPA general revenue requirements. Transmission service requests that do not meet their tests are subject to a BPA rate case.	Initially funded by transmission builder then: 50% of costs recovered from pricing zones and 50% recovered pro rata from initial generator(s) and subsequently from new generators as they come online.	Must seek cost recovery first at FERC. If FERC rejects cost recovery, CPUC will address retail cost recovery on project-by-project basis, with intent to allocate to customers of all CPUC-jurisdictional utilities in California.
Long term generator payment	Generators pay pro rata share of going forward costs starting at time of interconnection.	None	None	None, but agreement binds customer to take transmission service.	Generators pay pro rata share going forward.	None for network facilities; see below for non-network facilities.

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Advance Commitment	Eligible transmission project must have a demonstrated interest of 60% or more of transmission capacity, of which at least 25% is from interconnection agreements. Other 35% could be from power contracts of five years or longer; additional interconnection agreements; being in the CAISO interconnection queue and paying a cash deposit to the CAISO equal to the cost of all interconnection costs; or a cash deposit of 5% of a generator’s pro rata share of the capital costs of a proposed location-constrained transmission facility. Generators must also demonstrate site control or provide a \$250,000 deposit in lieu of site control.	Prior to approval of a permit to build transmission, developers must deposit letter of credit for 10% of their assigned share of the estimated costs identified in the transmission plan. Deposit returned if developer takes transmission service within one year of it being available.	None	One year’s worth of transmission charges in advance, unless customer pays for transmission upgrade costs in advance. For contracts less than 10 years customers will additionally provide one-half year’s transmission charges in advance for each year below the 10-year threshold. Existing transmission service requests may be extended to 10 years and beyond.	Not clearly defined, but envision requiring a commercial commitment from generators of over 50% but less than 100% of the capacity on the transmission line.	Bulk transmission facilities expected to accommodate multiple RPS-eligible generators. Gen-tie facilities must have at least one CPUC-approved RPS contract. Generators expected to pay pro rata costs for non-network facilities going forward once interconnected.

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Cost cap	Limited to 15% of total net high-voltage transmission plant investment of participating transmission owners in CAISO.	None. Subject to traditional regulatory oversight.	None. Subject to traditional regulatory oversight.	None	Not specified	None. Subject to project-specific California PUC approvals and traditional regulatory oversight.
Determination of zones or clusters	Recently formed Renewable Energy Transmission Initiative will help define energy resource areas. Ultimately, the determination of energy resource areas will be conducted and certified by the CEC and the CPUC. Until this certification is complete, the CAISO Board of Governors will have the authority to designate energy resource areas on a case-by-case basis. Out-of-state areas may be designated by CAISO in accordance with local Commission approval.	Determined by PUCT based on studies done by ERCOT and SPP, developer financial commitment, and other stakeholder input. Acceptable forms of developer financial commitment include existing renewable energy projects, pending or signed interconnection agreements, letters of credit, interconnection studies by ERCOT or transmission provider, or a non-utility entity’s commitment to build transmission.	Determined by Colorado PUC through studies submitted by the utilities.	Open season will determine zones or clusters to study for new transmission. All those requesting transmission service must participate in open season and sign a precedent agreement to be included in the studies and maintain queue position.	MISO will analyze requests in queue to identify areas eligible for this process.	Does not apply.

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Rights or priority given to generator in return for payment	Since LCRI Facilities are not networked and congestion is not a factor, firm transmission rights are not applicable. Generators will have contractual rights to their pro-rata share of the facilities.	Still to be resolved. ERCOT LMP market to launch in 2009.	Not applicable	Prepayments can be used for transmission credits but only up to 50% of the transmission cost. Credits remaining at the end of the contract can be used on extensions of the contract or will be forfeited. If BPA cannot provide service by contract start date, customer will be offered conditional firm service in queue order until all conditional firm capacity is contracted for.	Generators could receive transmission rights proportional to their share of the going forward costs.	

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Queue Interactions	Projects in CAISO queue may be input to determining resource zones, although that is not clear yet.	ERCOT used wind profiles developed by AWS TrueWind and informal input from stakeholders to develop transmission alternatives for potential zones.	Xcel Energy used its interconnection queue, as well as expressions of developer interest, in defining resource zones.	Those with queue requests must participate in BPA open season for new transmission to maintain queue position. No party is required to modify OASIS request. Short-term requests have rollover rights.	Current queue positions retained during evaluation process or if a generator decides not to participate and wishes to follow individual interconnection process.	Not directly, although projects in queue may act as indicator of interest in gen-tie or transmission line.

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Status	Conditional approval given by FERC. CAISO FERC filing in October 2007	Bill passed 2005; rules developed in 2006. PUCT interim order in October 2007 designating five zones that may support 10,000 to 25,000 MW. ERCOT now performing CREZ transmission optimization study and wind integration study. Final PUCT order expected in Spring 2008 specifying transmission plan necessary to serve designated MW levels in each zone. Transmission providers to be selected in 2008. Transmission permit applications expected by 2009 with first approvals by PUCT in 2010.	Bill passed in 2007. Xcel Energy filed three proposed energy resource zones for eastern and southern Colorado, and an application for a 345-kV line.	Under discussion. If adopted, open season would occur in early 2008.	Draft issued for discussion.	Enacted as part of California RPS in 2002; revised order by CPUC in 2006.