UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Technical Conference on Generation	**)**	
Market Power and Affiliate Abuse	**)**	**Docket No. RM04-7-000**
	)	

Remarks of
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On Behalf of
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1. Introduction

The National Rural Electric Cooperative Association ("NRECA") is a not-for-profit national service organization representing approximately 930 not-for-profit, member-owned rural electric cooperatives. The great majority of these cooperatives are distribution cooperatives that provide retail electric service to over 36 million consumer-owners in 47 states. Kilowatt-hour sales by rural electric cooperatives account for approximately 10 percent of total electricity sales in the United States. In addition, NRECA members include approximately 65 generation and transmission ("G&T") cooperatives that supply wholesale power to their distribution cooperative owner-members. NRECA's membership includes both transmission-owning and transmission-dependent utilities.

Rural electric cooperatives, both G&T and distribution, were formed by their member-owners to provide electric service to their members at the lowest reasonable cost consistent with adequate and reliable service. While certain NRECA members generate their own power and make sales of power in excess of their own members' needs to third parties in wholesale markets, most electric cooperatives are net buyers of power. Overall, cooperatives purchase more than half of their requirements from other wholesale suppliers. NRECA is therefore very concerned about possible exercises of generation market power by public utility power sellers that could cause prices in regional wholesale power markets to rise above just and reasonable levels.

While most cooperatives' sales for resale of power are not subject to this Commission's jurisdiction because of their status as borrowers from the Rural Utilities Service ("RUS"), some cooperatives are no longer RUS borrowers, and hence the Commission now regulates their sales for resale under the Federal Power Act ("FPA"). A small, but growing, number of cooperatives therefore have applied for and received market-based rate authority from this Commission. NRECA is therefore also concerned that these members' ability to make sales at market-based rates not be impaired by unduly burdensome restrictions.

Because of the unique concerns and situations of its various members, NRECA must look at the issues raised in this docket from more than one standpoint. It must recognize the concerns of those members that rely on regional wholesale power markets to obtain their power supplies about the existence and misuse of generation and transmission market power by public utility sellers. At the same time, NRECA must acknowledge the concerns of other members that sell power into those same markets under Commission-granted market-based rate authority about increasingly burdensome federal regulation of their activities.

The need to balance these sometimes conflicting viewpoints makes NRECA sympathetic to the difficult task the Commission must undertake in this docket: ensuring just and reasonable rates for wholesale power sales, through competition where possible, and through mitigation or cost-based ratemaking where competitive forces do not provide the necessary market discipline. I hope that these comments can assist the Commission in that task.

2. Comments on Regional Market Competitiveness Analysis

My remarks reflect my perspective as an economist on the issues, although clearly I would not be sitting here today if NRECA and its member cooperatives did not generally agree with them. In the time allotted to each panel member and to the general discussion, I believe that we can only scratch the surface of the issues raised by the Commission's questions. But it's a good place to start, and I thank the Commissioners and the Commission staff for giving me the opportunity to contribute to the conversation.

The Commission has focused the attention of this panel on the issues of "how best to define the geographic scope of electricity markets outside of RTOs or ISOs, and whether the Commission should analyze the competitiveness of the market rather than whether individual firms have market power." Before addressing this, I would like to point out that NRECA believes membership or participation in an RTO or ISO does not necessarily eliminate the existence of market power nor is it necessarily sufficient to fully mitigate the exercise of market power.

First, some general comments to lay the foundation and perspective for my answers to the specific questions posed by the Commission.

- The geographic scope of electricity markets depends upon physical factors (*e.g.*, transmission constraints) and institutional factors (*e.g.*, seams and transmission rate pancaking) that limit the geographic scope of competition. These two sets of factors should be the top focus of the

Commission's policy reform efforts. Removal of these two impediments, to the extent economically feasible, may be the most significant step the Commission can take toward addressing these vexing market power problems. The analysis of competitiveness of geographic markets and the analysis of market power of individual public utility competitors in those markets must therefore take both the physical and the institutional factors into consideration in defining the relevant geographic markets.

- This may mean that regions as initially defined will be redefined into subregional markets in a "first cut" because physical or institutional factors create import limits that make them the relevant geographic markets for analysis.
- In any event, the Commission should analyze the competitiveness of each region and relevant geographic market (as defined by limiting factors). If the Commission finds a market is not competitive (*e.g.*, it finds load pockets), it should analyze the individual public utilities that are likely to have market power in that relevant geographic market.

A. What are the advantages and disadvantages of using a regional market approach?

To assess the advantages and disadvantages, we first need to define what we mean by "a regional market approach." I believe that, for each "test year," a "regional market approach" is a process that would run approximately as follows:

- The process begins with an assessment of the competitiveness of each region. Because power system conditions (particularly transmission constraints) change from hour to hour, this assessment should be developed for a sample of seasonal peak and off-peak periods.
- If the regional market is competitive in all sample periods, the process is complete.
- If the regional market is *not* competitive, then it is necessary to identify the particular public utilities that possess market power, and to take steps to mitigate that market power.

As the Commission notes, a regional market approach offers several advantages, the most important of which to me appear to be ease of administration and consistency in the treatment of the various market participants:

- Assessment of regional competitiveness could be performed a single time for each test year, rather than over and over again for each applicant for market-based rates.
- Data could be obtained from all public utilities at the same time, thus substantially reducing data gathering problems and allowing data to be collected on a consistent basis, as defined by the Commission and with an appropriately uniform level of detail.

The regional market approach can therefore reduce administrative costs for the Commission and market participants. Furthermore, a single analysis of market competitiveness can be consistently applied to all applicants for market-based rates in the region.

There are no significant disadvantages from my point of view, provided that the analysis is sufficiently granular that load pockets are identified and buyers in these areas are assured just and reasonable rates. I can also imagine that applicants under the current system, who possess an informational advantage going into a review of a market-based rate authority application, could see a disadvantage to leveling the informational playing field.

What would be required to implement a regional analysis?

With respect to the second part of the Commission's question, the Commission needs to complete at least four principal tasks.

- Define the regional markets to be analyzed.
- Define the market power tests.
- Identify the data required to implement those tests.
- Specify the time periods to which the analysis applies, the dates by which all suppliers need to provide data to the regional market monitor, and the dates by which the regional market monitor will provide results to all parties.

FERC should not shy away from developing market power analyses that, to the extent needed, require increased collection of data from public utilities. The Commission should, of course, ensure that it has adequate staff and resources to make effective use of that data to analyze the competitiveness of a region, identify import-constrained markets and assess the market power of individual competitors in those markets.

B. What factors should be considered at the screen stage to demonstrate that the relevant geographic market is broader than a control area?

The geographic scope of each electricity market should be defined primarily according to prevailing transmission constraints, and secondarily according to any institutional factors (*e.g.*, seams and transmission rate pancaking) that may limit the geographic scope of competition.

C. What elements do buyers believe are necessary for a market to be competitive?

Basically, buyers need to have access to the supplies of many suppliers. This means that transmission constraints cannot limit access to supplies unless there are already many suppliers competing within the import-limited region. Within each import-limited region, the Commission can use structural measures of market concentration (such as market shares or HHI-type screens appropriate for electric markets) as initial screens for determining whether many suppliers can serve buyers.

D. Can a competitive market finding be compatible with a finding that competitors possess market power?

In general, the answer is no, *so long as the scope of the regional market is appropriately defined*. If a market is competitive, given the element that I stated is the most important from a buyer's perspective, suppliers do not possess market power. The converse, however, could hold. An analysis could find that a region is non-competitive but find that individual competitors do not possess market power. This therefore, requires examination of individual competitors.

E. If a region is found to be non-competitive, how will the interests of buyers and sellers that do not possess market power be protected?

The analysis of regional competitiveness is only the first stage of the assessment. The second part of the analysis protects the interests of buyers and sellers that do not possess market power by conducting analyses of individual buyers and sellers within the region to determine which entities possess market power. Based on the outcomes of the second stage, suppliers who are found to possess market power can be limited to charging cost-based rates until such time as the market can be shown to be competitive, or there is a clear demonstration that they do not possess market power.

F. What types of generation market power mitigation should the Commission consider besides cost-based rates?

In RTO-administered short-term markets, it should be sufficient for suppliers with market power to have their bids limited so that prices are constrained to just and reasonable levels, levels that would include verifiable incremental costs of commitment and dispatch and that would not necessarily induce withholding of supply.

In long-term markets and in non-RTO markets, there is no obvious behavioral alternative to cost-based rates. In all cases, there is the structural alternative of horizontal division of generation ownership; but I am not recommending that the Commission consider this alternative.

3. Regional Market Approach Action Items and Timetable

I was encouraged when I saw that the Commission organized a panel to focus on a regional market approach because the questions posed for this panel echoed some of the very same comments that my colleagues and I at Christensen Associates advanced to the Commission in February 2004 in the Blueprint that can be obtained by going to the LRCA website at LRCA.com. With only a minute remaining in my time, I can only direct your attention to Table 1, which lays out some key action items and a timetable for developing a regional market approach, including improving the interim market power assessment tools that have been proposed by the Commission. Table 1 defines what we believe the Commission can do now, what it can do in the intermediate future (say around 6 months to a year), and what can be done in the longer term in the following areas: defining product markets, defining geographic markets, developing screens, data collection, and standardization and development of computational tools.

That concludes my opening remarks. I thank the Commission for giving me the opportunity to provide comments today. I look forward to further discussion of these points.

Table 1
Regional Market Approach Action Items and Timetable

When	Define Product Markets	Define Geographic Markets	Develop Screens	Data Collection	Computational Tools
Now	Expand to include reserve and capacity markets as well as spot energy.	Define geographic markets for energy and operating reserves according to widely perceived transmission constraint-defined boundaries. Initiate a process for developing power engineering criteria for geographic definitions.	Identify the "best" handful of screens. Enhance the set of screens to address possibility of tacit collusion.	Determine data requirements. Inventory data currently collected. Develop plan for enhanced data collection and data management.	Implement several market power metrics. Begin development of power flow engineering models. Begin development of multidimensional market power screening system.
6 months	Expand to include longer-term forward markets	Initiate use of power engineering criteria for geographic definitions.	Enhance structural screens. Integrate structural and behavioral screening. Move from single screens to multidimensional screening process.	Conduct more rigorous power system analysis to reveal common load pockets. Develop bilateral trade reporting procedures.	Implement multidimensional market power screening system. Develop model validation methods.
Beyond	Expand to include bi-lateral trades	Refine the use of power engineering criteria for geographic definitions. Pursue transmission expansion policy to reduce barriers	Continually refine/enhance multidimensional screening process. Develop "control knobs" to fine tune and manage false positives and false negatives	Strive for close to real-time collection on all transactions. Continually refine data collection and data management efforts.	Continually refine/enhance market power assessment models. Continually refine/update power flow models. Use updated models to process MBRA applications.