PJM MMU Proposed Market Power Mitigation Protocol for NICA Capacity Markets
December 8, 2003

1. Capacity Market Conditions in NICA (Northern Illinois Control Area)

   There is currently no formal capacity market in the NICA. PJM has made a number of proposals addressing the capacity market structure to be implemented including, most recently, a proposal to institute a market based on a capacity auction. Regardless of the exact design, it is expected, when the capacity market begins, as the result of the structural conditions in the NICA market, that the capacity market in the NICA will face market power issues. It is expected that the structure of capacity ownership and the nature of the capacity markets will result in the ability of some generators to exercise market power in the NICA capacity market.

   The calculated HHI for the NICA capacity market is 2150. In addition, the MMU analysis indicates that one generator currently owns or controls more than fifty percent of total capacity in NICA and that at least two generation owners will be pivotal in the capacity market. In other words, the capacity of these owners will be required in order to meet total load obligations to purchase capacity.[1] [2]

2. Market power mitigation

   a. Introduction

      Based on the analysis of competitive conditions, market power mitigation measures are required for the NICA capacity market. These measures should be implemented at the currently anticipated opening of the capacity markets on June 1, 2004. If a PJM operated capacity market is utilized at the time of integration, March 1, 2004, mitigation measures must be in place at that time. Again, the market power mitigation measures are designed to strike a balance between preventing the exercise of market power and ensuring that a competitive market price signal is permitted to emerge from the markets.

      No explicit monopsony-based market power mitigation rules will be proposed at the outset of this market. The fact that the markets will be based on a centrally operated auction and that LSEs must purchase an externally defined and publicly posted quantity of capacity resources is expected to limit the exercise of monopsony market power. Nonetheless, the potential exercise of monopsony power in the capacity market will be carefully monitored by the MMU as the market develops.

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[1] Report Regarding the Expected Competitiveness of Markets in the Northern Illinois Control Area After Integration Into PJM, August 7, 2003.

[2] Appendix to Report Regarding the Expected Competitiveness of Markets in the Northern Illinois Control Area After Integration Into PJM, September 24, 2003.

b. Stakeholder input

The MMU has met individually with some owners of NICA generation, with representatives of NICA load and with broad NICA stakeholder groups. The MMU has also issued a general invitation to all NICA market participants to discuss any concerns about market power issues and market power mitigation issues. The MMU will request that PJM convene stakeholder meetings to discuss the market power mitigation mechanism proposed here for the capacity market prior to the integration of NICA on March 1, 2004 and prior to the implementation of a NICA capacity market on June 1, 2004. The MMU also continues to invite individual comments and discussions from all parties. Based on the comments received, the MMU will consider making appropriate modifications to the proposed market power mitigation mechanism.

c. Market power mitigation measures

The proposed mitigation measures are designed to limit offers in the capacity market to the incremental cost of capacity, where incremental cost is the additional, uncompensated, avoidable cost of offering capacity into the specified capacity auction including, where relevant, going forward cost, opportunity cost and risk. In addition, these mitigation measures address market pricing during periods of shortage or scarcity by permitting the price of capacity to increase during such periods.

The market power mitigation measures are based on the concept that offers of capacity in a competitive capacity market would be based on the incremental cost of capacity. The incremental cost of capacity is the additional, uncompensated, avoidable cost that must be incurred in order to maintain a unit as a capacity resource in the capacity market. If a unit is covering all of its annual avoidable costs from energy market net revenues, the additional cost incurred in order to maintain the unit as a capacity resource is zero. If a unit's net revenues are zero, then the additional, uncompensated, avoidable cost of maintaining the unit as a capacity resource equals all of the unit's going forward costs. In other words, if a unit expects that its energy market revenues will equal its short run marginal costs of producing energy then it will remain in business only if it can recover at least its going forward costs in the capacity market.

The MMU proposes to establish default maximum offer levels in the capacity market based on estimates of incremental cost for three broad categories of generation. These default offer levels could be used by sellers of generation or such sellers could propose modifications to the levels, based on a quantification of components of capacity related costs. The MMU has evaluated going forward costs by broad category of generation. The categories used are peaking plants (e.g. combustion turbines), mid merit plants (e.g. combined cycles) and base load units (e.g. steam units). Going forward costs include long term operation and maintenance costs and other annual, avoidable expenses including labor, insurance and property taxes. Going forward costs are the costs that would be avoided if the unit were not in operation. Going forward costs do not include fixed costs like debt service or return on equity.

In addition, the MMU evaluated net going forward costs based on the simulation analyses of the NICA markets described in the MMU Report of August 2003 and the MMU Appendix of September 2003, cited above. Those simulations, and the data inputs for those simulations, were used as the basis for the expected net revenues for each broad category of generation. Net revenues are total energy market revenues less the short run marginal costs of energy production including fuel costs and variable operating and maintenance costs. Net revenues are available to cover all other variable and fixed costs of generation. The simulation results include hourly prices and hourly dispatch for each unit, which when combined with unit specific cost characteristics, can be used to calculate net revenues by unit and by unit type. The simulation results are, as noted in the referenced reports, based on an optimal, security constrained dispatch for units based on their cost-based offers, the underlying transmission system and the specified assumptions about hurdle rates.

The simulation results indicate that net revenues do not cover going forward costs for combustion turbines and that net revenues do cover going forward costs for combined cycles and steam units. In other words, based on the marginal costs of capacity, the appropriate offer price limits for capacity are positive for combustion turbines and zero for combined cycle and steam units. This does not mean that such mid merit and base load units would not receive a positive price. In the proposed capacity market, all units receive the clearing price. Thus, if a combustion turbine is at the margin, all units that cleared in the market would receive a price based on the capacity costs of the combustion turbine. The MMU estimates that going forward costs for a combustion turbine are $30 per MW-day and that, at the margin, the net revenues are zero. Thus, the offer limits for a combustion turbine would be $30 per MW-day. The offer limits for mid merit and base load units would be zero.

This result does not include any explicit calculation of opportunity costs or risks. The opportunity costs, in the simulation, are zero as all units are selling power at the market price available to them. There is no higher energy market price available to these units and there do not appear to be any alternative capacity markets. It is also not clear that there are any incremental risks associated with the sale of capacity.

The MMU also proposes that when total capacity in the market exceeds the total demand including a reserve margin by less than one percent that the offer price limit for capacity should equal the incremental cost of a new combustion turbine net of expected revenues from the energy and related markets. When the capacity market is close to scarcity, capacity market prices should be permitted to reflect that fact. This feature is designed to permit scarcity pricing in the capacity market when conditions warrant while maintaining protections against market power required by the absence of a competitive market. The threshold is based on historical analyses of pricing in the PJM capacity markets. It may be appropriate to have two steps in the offer price limits as the available capacity approaches the total demand, with an intermediate step at a two percent excess point. The incremental costs of a new combustion turbine are the full annual carrying charges of the unit, including fixed costs, or approximately $165 per MW-day on an installed capacity basis.

For example, if total load plus a reserve margin were 50,000 MW, the capacity market price would equal $165 per MW-day when the capacity available in the market is less than 50,500 MW.

Finally, the MMU proposes that it have one week to screen offers before the clearing price for any capacity auctions in NICA are final and the clearing price is posted. All offers at or below the stated offer limits would be deemed competitive. If the auction were deemed competitive, the clearing price would be posted. If the auction were not deemed to be competitive, the auction would be rerun.