Testimony of

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"Capacity Markets in the PJM Region (Docket No. PL05-7-000)"

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Good afternoon Commissioners and Staff. My name is Stephen Wemple and I am the Director of Retail and Regulatory Affairs for Consolidated Edison Energy, which is subsidiary of Consolidated Edison, Inc. Con Edison Energy and its affiliates Con Edison Solutions and Con Edison Development, are active in the New York, New England and PJM markets, and collectively own 1,500 of merchant generation and supply approximately 2,000 MW of retail load.

Last year I testified before the Commission in the Technical Conference on compensating generators in load pockets which addressed many of the issues that are also being discussed in this proceeding. Specifically, last year's Technical Conference stressed the importance of designing market solutions to attract and retain the resources needed for reliability[1]. That principle is arguably even more applicable today. Simply put, market solutions allow all resources including traditional generators, transmission and demand response to efficiently compete to meet the reliability needs whereas non-market solutions result in discriminatory compensation and create unhedgeable costs for customers and typically fail to attract an appropriate level of demand response.

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[1] PL04-2-000

My comments today focus on some of the shortcomings of the current PJM capacity construct and outline the importance of including demand response as a full participant in the PJM capacity markets. As you are aware, PJM's current capacity market equally values all network resources throughout the PJM footprint and relies on the transmission system to ensure that the aggregate supply is deliverable to load. While this approach worked reasonably well when it was first adopted, there are problems applying it to the expanded PJM footprint because reliability cannot be maintained if customers procure their entire capacity exclusively from remote generation which can be located as far as 800 miles away. At the same time, the general surplus of capacity within PJM has been pushing capacity prices to historically low levels, providing a false sense that there are no reliability concerns in constrained areas, and sending an economic signal to those resources needed to maintain reliability that they can and should retire. This has forced PJM to offer Reliability Must Run (RMR) payments to retain some generators but not to other suppliers (including generation and demand response) providing the same reliability service.

In order to achieve an efficient market outcome, the PJM capacity market must be restructured to provide both demand response and traditional generators a consistent and non-discriminatory price signal when they are providing the same reliability service. For example, if units needed to maintain reliability within a given load pocket require a payment $50/KW-year to remain in service, demand response and other suppliers within that load pocket should also be eligible for the same payment. This ensures that customers can hedge their costs by either installing demand response measures or contracting with local suppliers.

Moving to the specific proposals to replace the current capacity market, in my opinion, the proposed RPM would do the most to foster Demand Response participation in the capacity markets.

Under the RPM proposal, Demand Response participants can either sell their capacity on a forward basis in the PJM administered auctions or elect to participate after the forward auctions are conducted by enrolling in the Interruptible Load for Reliability ("ILR") program three months before the start of the delivery year. Because the capacity value that ILR participants will receive is predominantly based on the results of the Base Auction conducted four years earlier, Demand Response participants can use the results of the Base Residual Auction as an effective floor price to determine the future value of potential Demand Response strategies. Under the proposed RPM, when a customer commits to participate in a given year's ILR program, they will effectively know the ILR value for the upcoming delivery year as well as the following three delivery years. This forward valuation can help customers and Demand Response providers determine what installations and/or equipment upgrades are cost effective and should be pursued. For example, projects requiring less than 10 months[2] of lead-time will have a known revenue steam that they can count on for their first four years of operation.

The RPM auction timeline also allows customers with existing and planned Demand Response projects multiple ways to optimize their capacity value. For example, Demand Response can be offered into the Base Auction four years forward at a relatively "high" desired price, knowing that if they are not cleared in that auction, the ILR option gives them a

[2] 10 months is the time from the Base Residual Auction until the following year's ILR commitment deadline.

second chance at obtaining the equivalent value without the four year forward commitment. In addition, Demand Response measures that do not clear in the Base Auction can participate in subsequent Incremental Auctions and presumably would seek a higher price than had cleared in the Base Auction in order to improve on the anticipated ILR price.

Although ILR participants do not directly interact with the Base Residual Auctions, the RPM design ensures that Demand Response will impact the clearing price of the Base Residual Auction and reduce capacity costs for all consumers. This is because PJM assumes a quantity of ILR ***will*** participate in the planning year and therefore clears the Base Residual Auction as if that amount of ILR had directly participated and was cleared in the auction. For example, if 5,000 MW of ILR is assumed to participate in a given planning year, PJM will clear the Base Residual Auction at a price as if that 5,000 MW was part of the supply stack and had offered to sell at less than the auction clearing price.

In contrast, the Enhanced Integrated Transmission & Capacity Construct is not likely to attract as much demand response, especially in zones and local load pockets, and is more likely to result in unhedgeable costs because it relies on RMR payments to solve any reliability needs in an area smaller than the two relative broad locational capacity markets proposed for the Eastern MAAC and Southwestern MAAC regions. This coarse approach to local capacity markets ensures that if the Eastern MAAC market fails to generate a price high enough to retain resources needed for the PSEG zone, an out-of-market payment will be made to specific PSEG suppliers in excess of what is paid to existing generators and demand response suppliers within the PSEG zone. That in turn will impose unhedgeable costs on customers in the PSEG zone and will fail to attract those demand response measures that would be cost effective compared to the RMR payments.

In conclusion, I'd like to reiterate that RMR payments are non-market solutions that prevent other resources including Demand Response measures from realizing the full value of the reliability service they can provide. Because both the existing PJM capacity market and the proposed Enhanced Integrated Transmission & Capacity Construct rely on RMR payments to maintain local reliability, they will depress the price that Demand Response measures would otherwise receive under a true market solution, lead to less Demand Response participation and result in a less than optimal solution to PJM's locational reliability requirements. Furthermore, the customer impact under a market solution is significantly different than under an RMR solution. Market solutions can be hedged and allow customers with Demand Response capabilities to self-supply their reliability requirements. In contrast, RMR payments impose unpredictable and unhedgeable costs on consumers.

Thank you.