FIRST DRAFT

Small Customer Aggregation Proposal for Real-Time Markets

As NYISO proceeds with the development and implementation of the new Real Time Scheduling and Real time Dispatch (RTS/RTD) system that will displace the current BME/SCD setup, participants need to better define the terms under which demand side resources[1] (DR) will participate in these markets. NYISO already has in place a Day-Ahead Demand Response Program (DADRP) that allows DR to participate in the NYISO Day-Ahead markets on terms comparable to generators. DR may submit startup cost bids, include minimum run times, and otherwise exercise the same flexibility offered to supply resources. The intent of the evolving RTS/RTD system is to allow DR similar flexibility in the Real-Time markets.

In the case of large (>1 MW) DR resources, it is here assumed that the resource will employ substantially identical metering and communications infrastructure as a generator visible to the ISO would use, depending on the markets it wished to participate in. At the simplest end of the scale, a large DR resource participating in the energy market on a self-scheduled basis would require metering capable of sending meter data to the ISO every fifteen minutes and would need to be able to submit bids over the internet on a fifteen minute basis as well. DR wishing to participate "on dispatch" would require real-time metering and the ability to communicate that information back to the NYISO on a five-minute basis. Such resources would also be expected to be able to receive and follow five-minute basepoints. Finally, those DR resources able to participate in the demanding regulation market would need to be able to send meter data and receive and respond to basepoints on a six-second basis.

It is also assumed for this discussion that the rules for DR participation in energy, capacity, and ancillary services markets are being developed elsewhere, but that the requirements for DR are substantially similar to those applicable to generators, including penalties, if any, for non-performance. The current RTS/RTD Concept of Operations envisions DR participating in all NYISO markets to the extent it can meet the scheduling, performance and metering requirements. It is assumed that DR will actively participate in at least the energy and capacity markets, that some resources will also elect to participate in the non-spinning reserve markets and others may even be able to support the spinning reserve and regulation markets.

While direct metering and scheduling of larger individual DR resources may be practical and not prohibitively expensive, it is highly unlikely that small DR resources will find it economically attractive to participate in this same manner, nor do system security needs require this same level of integration. This paper proposes an approach that would allow small DR to participate in he NYISO real-time markets on an aggregated basis. Not only is doing so necessary to allow small customers to meaningfully participate in NYISO energy markets – a goal endorsed by NYISO and FERC on its own right – it is also likely to be the primary means by which significant amounts of DR will ultimately be able to participate in the dispatch and regulation markets.

It seems unlikely that more than a few very flexible DR resources will find changing load and tracking basepoints on a five-minute basis to be compatible with their primary business needs, much less following regulation signals on a six-second basis. Instead, it seems likely that the best means of demand participating in these markets will be via the centralized control of hundreds or even thousands of relatively small loads in a manner that is essentially transparent to those persons associated with those loads. For this to be feasible, small loads need to be able to be aggregated by Curtailment Service Providers (CSPs) for participation as a much larger "virtual" generator.

NYISO recently adopted a 25 MW Small Customer Aggregation program that allows loads otherwise too small to participate in the DADRP, EDRP or SCR ICAP programs to do so by proposing alternatives to

[1] / DR is intended to include both pure demand reduction measures and distributed "inside the fence" generation where customer load normally exceeds local generation capability.

per-site interval metering[2]. Verification protocols must be approved by the NYISO and reviewed by certain market participants. So far, Consolidated Edison and LIPA have instituted programs, both relying on averaging techniques and direct control of home air conditioning units via the Internet. Results of these programs are not yet available. This program forms the basis for the suggestions below.

It is proposed that CSPs (including RIPs, LSEs and others allowed to offer DR into the market) be allowed to enroll end-user loads smaller than 5 MW on an aggregated basis. Each load would be associated with a virtual DR resource, which would, in turn, be registered with the NYISO as a Demand Resource Unit (DRU) or "generator" in the appropriate NYISO markets. Each such resource would be required to abide by all of the same bidding and scheduling rules applicable to conventional generators participating in the same markets.

DRUs would be registered in the same general manner as generators and their definitions should not be modified very frequently (monthly at most, perhaps once per capability period). It would be the responsibility of each Demand Resource Unit to bid in, schedule, adhere to schedules and follow basepoints on an aggregate basis, utilizing the flexibility inherent in the many individual load response or DG resources that make of the Demand Resource Unit.

To the extent necessary to ensure reliable operation of the bulk power system, DRUs would need to have their constituent resources located within the same LBMP Zone, subzone, load pocket, or possibly even bus. Where both the DRU and its constituent aggregated resources are small (say less than 10 MW) location within the same zone might be acceptable, while larger DRUs or DRUs with fewer, larger constituents might need to more proximate to one another in New York City. The details of the proximity requirements should be addressed with input from NYISO Operations staff, but should strive to allow aggregation over as wide an area as possible consistent with reliability.

NYISO would communicate with each DRU as it would an individual generator that is visible to the NYISO MIS and SCD system. The DRU would physically be a CSP "control room" from which individual DR resources are controlled (whether through wireless, internet or other means). Multiple DRUs could be located at each control room, but each would communicate on a unique basis with the NYISO, presumably using the NYISO's new ICCP ("direct generator") system.

Where a single large DR resource, such as an air products facility is enrolled in the market and controlled from such a control center, it would be its own DRU and, as noted above, would be individually metered and dispatched. That information would be passed directly through to and from the NYISO.

Where the DRU is made up of an aggregation of smaller curtailable loads and/or distributed generators, the CSP would be responsible for proposing metering and performance measurement protocols that are acceptable to the NYISO. The CSP responsible for that DRU would then be responsible for applying these pre-approved protocols and communicating the aggregated combination to the NYISO in the appropriate time frame and format.

The intent here is to develop an approach that recognizes the infancy of DR's involvement in markets by allowing those closest to the customers and their limitations to propose metering and verification protocols that respond to customer needs and limitations, while requiring that those protocols also recognize the needs of the NYISO.

If, after experience with various protocols it is warranted, the NYISO may choose to adopt standardized protocols for certain resource types. At the present time, it would be premature to define a single metering or verification protocol, other than to say that whatever is proposed by CSPs needs to be auditable, verifiable, and needs to avoid the potential for adverse reliability or market impacts.

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[2] / The 25 MW Small Customer Aggregation program is a pilot program and excludes participation by distributed generation. It is here assumed that the both MW and technology limits on the aggregation program will removed by the time the RTS/RTD system is operational.

EXAMPLE:
A CSP is marketing (1) a DR program for residential consumers using internet-based control of central air conditioning units, (2) a program for replacing diesel backup generators with new microturbines at grocery stores for activation some limited number of hours per month, and (3) a program involving remote dispatch of pumping load at water treatment facilities.

It might propose that the performance of the central A/C units be based on real-time (every five minute) feedback on total units activated and number of units where the reduction is defeated by the customer (based either on real time feedback or an assumed defeat rate) times an average reduction amount of X kW/unit. Thus the CSP is capable of accurately estimating the "output" of the A/C units every five minutes and changing that output even more frequently.

The CSP is employing a dial-up control and communication system for dispatch of the microturbines that is capable of providing operational data as often as each unit can be queried. For cost reasons, the CSP cannot poll each microturbine more often than once every three minutes.

Finally, the CSP's relationship with the water treatment facilities is such that it cannot directly control pumping output and does not have access to direct interval meter reads. The facilities are willing to be interrupted on 10 minutes notice by telephone and have the ability to directly read pumping load in their own control centers.

In the case, the CSP might choose to register two DRUs with NYISO. DRU-1 aggregates all of the units capable of metering and control on a five-minute basis – the A/C units and the microturbines. Since this unit can respond to five-minute basepoints, it is registered as a dispatchable unit. DRU-2 consists of the pumping installations. Because these units can be dispatched and metered (operator informs CSP of pumping load change following call to shut down) on a fifteen-minute basis, but not more frequently, DRU-2 is not registered as a dispatchable unit and will instead self-schedule it output with the NYISO on an hourly, half-hourly, or quarter-hourly basis.

None of the resources are capable of responding or reporting on a six-second basis, so neither of the DRUs will be bid into the regulation market.

It will be the responsibility of DRU-1's "operators" at the CSP to make sure that the aggregation of resources making up DRU-1 are capable of achieving the performance implicit in that unit's bids to the NYISO or face the penalties for not doing so. Furthermore, the CSP needs to make sure that its verification records support the operational information that it submits on behalf of DRU-1 to the NYISO. The same is true for DRU-2.