September 8, 2016 Regional EM&V Forum Webinar on Demand Response and Geotargeting: Questions and Answers from the Webinar

LINK TO WEBINAR SLIDES:
http://www.neep.org/sites/default/files/resources/Geotargeting_and_DR_Webinar_Slides_FINAL.pdf

Q &A on Demand Response Presentation

I've heard that Residential DR initiatives cannot currently participate in ISO-NE's Forward Capacity Auctions. Is this true? If so why, If not true, can you please site an example or two of residential projects that are participating?

Theoretically, they could participate, but recent rule changes that necessitate the ability to perform outside of the summer season and penalties for non-performance have led some program administrators (ex.- Eversource CT) to back out of even their C&I commitments in the FCM. (p. 30-31). ISO-NE also requires five minute telemetry for DR events, which isn't cost-effective for a residential customer, but ISO-NE has expressed a willingness to work with electric utilities to incorporate a "virtual meter" type methodology. (p. 37) The Massachusetts and Connecticut Program administrators are currently evaluating how they might incorporate DR into their Installed Capacity Requirement rather than bidding it into the FCM (p. 11).

Are there current legislative proposals that you favor regarding IDSM that lawmakers should be aware of? Or, more broadly, what are your current federal policy goals, especially from a legislative perspective?

I'm unaware of any legislative proposals specifically discussing IDSM.

I know you can bid DR into NYISO. What about EE?

Energy Efficiency isn't currently bid into the NY-ISO's wholesale markets. While they are in the midst of a redesign of those markets to facilitate participation of DER (see whitepaper here), it doesn't appear that EE will receive compensation in the envisioned redesign. The whitepaper notes that "Intermittent and passive resources that emerge will unlikely to be able to actively participate in the NYISO's wholesale markets. Rather, they will be integrated into wholesale markets indirectly, in the form of modifications to load forecasts through enhanced forecasting tools that will influence the dispatch of supply resources on the bulk power system." (p. 8)

How may demand response apply to gas customers and gas utilities? This is an issue where you are going to have different strategies deployed based on the generation mix. For instance in ISO-NE we are heavily dependent on natural gas for about half of the electric generation. Is there a synergy in their role when it comes to natural gas and demand response?

Yes, there is definitely a role, especially in the large C&I sector where you can encourage a customer via economic incentive to move their tasks to another time of day with enough notice, maybe with a days' notice or something similar. This reminds me of a conversation I had with a gentleman from a curtailment service provider who said they could provide demand response at a residential gas utility, but you can only do it once; he was eluding to the fact that if you cut off gas for more than a few hours, *you are looking at an adverse impact on the operation and maintenance of a home, for instance, leaking pipes, but there are opportunities for demand response for gas utilities, particularly on the C&I the side.*

Why are CA's savings lasting 3 years, whereas MA's savings are lasting only 1 year?

This is a matter of assumed measure life rather than persistence of savings. For the DR programs being piloted in Massachusetts, they are looking at a 1 year measure life (p. 34) because in the actual enrollment agreement with customers, they only enroll for one season at a time. In California's case, the commission assumes a 3 year life cycle for demand response programs and associated technologies (p. 35).

Brian cited some study/ survey/ analysis that shows that the customers who are engaged with smart technology are also interested in EE? What is the data citation survey behind that?

That data was a result of a survey by the Shelton Group articulated in their Report "Smart Home Strategies for Utilities: Five Reasons You Should Get in the Game" (p. 7). Also of value to webinar participants may be an Association of Energy Services Professionals (AESP) Survey *of Utilities and NARUC members of Demand Response, noting that regulators expected that their overall paradigm would be changing to include much more demand response intheir program over the next 5 years.*

I believe Central Hudson has developed plans to roll out AMI Meters.

Con Edison was the first distribution utility to have their advanced metering infrastructure (AMI) business plan approved, which included plans for rollout of 4.7 million electric and gas modules. In a statement celebrating the approval, PSC Chair Zibelman commented, "As the first-of-its-kind system in New York State, this is a milestone in Reforming the Energy Vision, Governor Cuomo' strategy to bring cleaner, more-resilient and affordable energy to all New Yorkers." Subsequently, Iberdrola (p. 114), National Grid (p. 238), and Orange and Rockland (p. 261) all filed Distributed System Implementation Plans (DSIPs) that include system-wide installation of AMI. Standing apart from the crowd, Central Hudson proposed only an *opt-in* advanced meter rollout, instead discussing in their DSIP filing how REV markets could function without advanced metering (p. 131)

Can you please repeat what E and D were in the National Grid example (LMP+E+D)? Thanks!

LMP+E+D is the equation that, moving forward, the New York Distribution System Platform Providers will use for economic dispatch of distributed energy resources. (See the National Grid Proposal for more information). LMP is location marginal pricing, derived from the NY-ISO CARIS report. D is the distribution system value. E stands for externalities, which right now, are limited to carbon emissions. In large part in the Buffalo Niagara Medical campus, the dispatch will be primarily generation, more than demand response, largely from combined heat & power, or diesel generators. It is a medical campus and has a backup generator of something like 25 MW of capability. So that generation will be dispatchedonce it becomes economic according to the LMP+E+D equation. The idea is that in the same way that ISO dispatches at the transmission system level, you are looking at the utilities dispatching at the distribution system level in the future.

Comment on engagement: National Grid's Smart Grid pilot showed high levels of customer satisfaction with critical peak pricing in the 2015 summer and similar responses expected for 2016. What are your thoughts on where this idea of new pricing models, like peak pricing models need to be integrated into these synergistic programs with demand response and energy efficiency in order to be the most effective?

I (Brian) am personally a fan of Peak Time Rebates (PTR), rather than Critical Peak Pricing (CPP). The customer gets to see that they are provided an incentive for reducing the usage at a certain time (PTR), rather than charging them an extra amount or maybe them not seeing that they are being charged extra (CPP). I think that being able to see the incentive is very important for the customer and that's one of the reasons why Maryland's emPOWER program with Baltimore Gas and Electric has been so successful. I'll note that their customer satisfaction rating from JD Power and Associates went way up after instituting the program and the customers love to see that they are actually saving money and being paid by their utility. (see description of BGE's rising score). We reserve judgement whether Time of Use (TOU) rates should be used with opt-in or opt-out programs. To the scale it was done in the Worcester Pilot Program, it was very successful. As for the grid modernization proceedings for MA, TOU has been ruled outside the scope of the current proceedings, but may be something to look at in the future. (p. 6) It may be important to note here that opportunities for time varying rates are very closely intertwined with proposals for rollout of Advanced Metering Infrastructure (AMI). Throughout the region, in our two most populous states (NY, MA) there is very little AMI, but regulators in both states are currently considering a major rollout of AMI. Con Edison just had their rollout approved of about 4.5 million Meters, and the New York Public Service Commission is considering system-wide rollouts of AMI in all the utilities except for central Hudson, who within their distributed system information plan (DSIP) has only proposed rollout on an opt-in basis. Between New York and Massachusetts we are looking at the possibility of billions of dollars in investment and bringing billions of dollars in opportunities and benefits that can be derived from customer interaction and increased data granularity.

In places where Integrated Demand Side Management (IDSM) standards have been established, such as CA, what aspects of program design have standards focused on, apart from what's typically already regulated and overseen in standalone EE and DR programs? In other words, what is the newest model showing about how IDSM programs are being evaluated, measured and verified?

Going back to the definition (IDSM programs "… support two out of three demand side technology types (EE, demand response, and distributed generation)), it was largely focusing on just 2 of the 3 EE DR distributed generation. But directly before that definition, The CPUC basically said, look we realize that right now these programs are going to largely be focusing on DR and EE, but in the future we are going to want to see a focus on integration of distributed generation as well. Aquestions remain there. For instance, EE and DR are often recovered through a surcharge on the bill of the customer, but is that something that utilities or others are looking to do for distributed generation, or even for energy storage, which in a lot of cases is classified in a similar manner to generation? That remains unclear. In MA in the most recent energy bill, says that in order to further incorporate energy storage into these types of IDSM programs and projects, energy storage can be owned by the utilities. In NY, they had a similar question that they covered in the REV proceeding and decided that distributed generation can't really be owned by the utilities (except for a few exceptions) and wouldn't be recovered on a customer's bill. This is an interesting place for a lot of development and it is exciting to see where we go next. For example, in MA the DOER, along with the CEC, produce a study on energy storage, as well as obtaining the ability, through new legislation, to prescribe targets for energy storage that might be incorporated into the energy efficiency program plan. Another question is how to balance funding allocation between *energy storage and energy efficiency, if the two strategies are jointly administered within the same program. These are just some of the interesting questions that need to be answered. For non-wires alternative projects, some utilities (ex. [Con Edison]) are soliciting a predetermined amount of load reduction via competitive bidding in a descending clock style auction that's technology agnostic. This might be an opportunity for other program administrators to explore in the future.*

Q&A on Geo-targeting Presentation

In the California case, the local value of EE resources is undercut by the use of building energy codes (Title 24) as the baseline for savings calculations, thereby reducing the yield from EE by as much as a factor of 5. (This is changing due to new legislation in CA) To what extent is this a problem in NE?

EE savings is increased by increased EE standards and building energy codes, though in some cases savings that can be claimed by program administrators are decreased. Title 24 is the most advanced building energy code in the country. So, the short answer is that our state code updates, adoptions and stringency is nowhere near the extent of title 24 in California. In the northeast, for example, we are still seeing states that are not even caught up to the 2012 International Energy Conservation Code (IECC), never mind the 2015 IECC. For a lot of our states in the region, they are currently reviewing or in the process of adopting the 2015 IECC, and in the case like MA, it has been adopted, but won't into effect until 2017. We see that similarly with a number of other states as well. Therefore, the baseline issue is not going to be as significant here as it would be there. While baselines related to energy code aren't as much as an issue, we are all facing the EISA standards and the phase out of a lot of the savings that were available in residential lighting sector. In California, AB 802 allowed CA program administrators to begin to claim savings for existing conditions baseline, but unsure where this legislation stands regarding regulatory implementation. The constraint that at least used to exist in California, which was theoretically intentionally designed to ensure that savings that don't really occur don't get counted, probably went way overboard in constraining estimates of what had actually been done. It is a really important issue of cost efficiency programming in general, whether it is system wide or geo-targeted, but if it were to be applied in geo-targeting situations, it would be enormously harmful to the ability to do geo-targeting.

For Nantucket is the capacity issue with the underwater cables or specific circuits on the island? Can you elaborate on the capacity constraint on Nantucket, is the issue and value of deferral primarily associated with the deferral of the need to put the new underwater cable in place or is it specific to individual circuits on the island, or is had also been noted that there was value associated with the potential need for some new diesel generators. Can you talk about the different components that would be deferred, and which ones have the greatest value associated with the deferral?

In the case of Nantucket, the key constraint is really the underwater cable bringing power to the island. They have 2 cables, which last 50 years. It is about reliability, and concerns arise when demand is higher than a single cable capacity. Right now they are forecasting that they will need a third cable by 2028. The study did not look in more details at the distribution level, or other areas of the distribution grid; it only focused on the prospective need of the 3rd cable (along with additional back-up Diesel generators on the island). There may be potential benefits of other elements of the distribution system, *but the analysis hasn't gotten to that level yet. Part of the recommendations is that all the components of grid infrastructure are included in the analysis.*

ConEd has been using a predictive approach for about a decade, called the Targeted DSM program. ConEd calculates the carrying cost of a proposed T&D investment to a capacity-constrained substation, and issues a bid solicitation for DSM resources with a price to beat. ConEd has acquired several hundred megawatts of DSM resources at a cost lower than the proposed T&D investments. Seems like this successful model could be replicated in MA, couldn't it? Are there any advantages/disadvantages to this approach?

The key advantage is that it is simple. You have the carrying cost that is proposed in the investment, you can issue a bid solicitation to the market for peak demand reduction, and select bids with a lower cost than the infrastructure upgrade. ConEd has been successful in using that approach to secure several 100 MWs. One issue with this approach is the risk of double counting benefits for avoided utility costs. If statewide avoided-cost values do not take into account these geo-targeted DSM investments, avoided T&D costs may be overstated. The other issue is that we are making an exception to the cost effectiveness framework that is used for other DSM activities for some projects. The industry is moving towards IDSM. Jurisdictions are thinking about how they can integrate their cost effectiveness methodology for DR and EE and looking towards other customer-sided renewables in the process. Exceptions for geo-targeted DSM goes in the opposite direction, and raises other concerns as well. Whether or not this is something to reproduce in MA, for example, is something for the utilities and regulators to decide.

As we start getting into this world and start trying to account for all the many types of values that different resources can bring in different ways, including the different types and quantities of options, if you are only bidding on the cost per kW reduced, you may not be coming up with an optimized solution. You can theoretically set up a bidding to differentiate between different types of values different resources would bring to the bidding, but that certainly gets a lot more complicated.

How does data sharing across utilities and third party vendors work? Are third party EE providers given access to customer-level data in order to target specific folks? Or what kinds of data are shared? Do customers have to give their consent?

The granularity of data shared with third party EE providers is an issue that regulators struggle with throughout the country. In New York for example, they held a conference last December as part of their REV docket to help iron out specific issues, with presentations from a wide range of stakeholders [1, 2, 3, 4, 5, 6, 7, 8, 9, and 10]. From what I understand, many issues related to data access remain up in the air, but one settled component of the debate is that the utilities will make data equivalent to the granularity provided by "Green Button Connect my Data" available to third parties upon customer request (either through Connect my Data or a similar protocol). The DSIPS contain a lot of information related to utility data access. In other cases, third party EE providers have to sign some form of non-disclosure agreement and comply with strict regulatory oversight.

Can you provide some examples of software tools that allow for utilities to do the DSM integration analysis?

There are a number out there, and we do not want to recommend one more than another, but I do think you can look into some offerings from Nexant and Integral Analytics. What is interesting with these offer packages is the ability to have locational marginal price analysis and DSM integration analysis done all the way down to the transformer level and to really get a good sense of the picture at a very granular level. We don't have specific names of software, but it is suggested to take a look at those two organizations. E3, a California based company, has developed a software tool that is customized to the work that ConEd is doing in New York, and has also done a lot of the non-wire analysis in the northwest and possibly working in California as well. So that is another firm that has done a lot of work on these analytical tools.

Minor correction. The applicable legislation in CA is AB 802, not SB 350. AB 802 allows existing conditions baselines. SB 350 doubles the state goals for EE and GHG reductions.

This is correct. Both energy bills were passed in the same session and I mistakenly noted SB 350 rather than AB 802.

It's my impression that scale (savings required for deferral) and timing (years to achieve the savings) limit feasibility of NWA projects to a greater extent than cost effectiveness. What are your thoughts on this?

That is only true if you let it happen that way. Several jurisdictions, because they were forced to proceed with capital projects because the projects were raised with too little lead time to do anything about them - in New England, VT, Maine, and others- , are now requiring long-term, 10-20 years, forecasts of T&D needs so that those opportunities are identified well in advance to allow time for the deployment, if in fact it is cost effective. If you set up your planning right, then cost effectiveness would be the primary driver, rather than scale or timing. Although this is not the case in several jurisdictions or utilities where T&D planning horizon are only for a 3-5 years period.

Right now, scale and timing are a significant constraint, but it doesn't need to be.

What about measuring the results of NWA vs. planning for the program? What technologies can assist with this?

There are no fundamental differences between M&V for a NWA to a capital project and for other DSM activities except on two fronts: timing and accuracy. M&V activities should provide timely results of the NWA project, to allow time for corrective actions if required in order to meet the peak reduction targets at the appropriate time. Accuracy is also a key aspect of M&V activities for NWA, and should be sufficient to meet grid planning needs.

Ultimately, SCADA data from the grid will be the true measure of NWA successes. Furthermore, as stated in the NEEP Geo-targeting report, "big data" and the new analytical tools enable more sophisticated strategies for both planning and M&V for DSM programs of all kinds. Also, impact assessment should focus first on the T&D reliability need, and assess the extent to which the forecast T&D need has changed as a result of the NWA solution, the magnitude of the T&D peak reduction or production that has been realized. It is worth reinforcing that reliable and malleable planning tools are needed to create more accurate and detailed models of loads and economic information to gain a better understanding of the available savings.