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Considerations for State Regulators and Policymakers in a Post-FERC Order 745 World

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Acronyms

ARC	Aggregators of Retail Customers
Auto-DR	Automated Demand Response
BGE	Baltimore Gas and Electric
COPUC	Colorado Public Utility Commission
EDRP	Emergency Demand Response Program
“EPSA”	<i>Electric Power Supply Association vs. FERC (“EPSA”)</i>
DR	demand response
FERC	Federal Energy Regulatory Commission
I&M	Indiana Michigan Power Company
ICAP/SCR	Installed Capacity / Special Case Resource program
ISO/RTO	Independent System Operator / Regional Transmission Organization
IURC	Indiana Utility Regulatory Commission
NEPGA	New England Power Generators Association
NYDPS	New York Department of Public Service
NYSERDA	New York State Energy Research and Development Authority
Open ADR	Open Automated Demand Response

1. Introduction

By vacating the Federal Energy Commission's (FERC) Order 745 in *Electric Power Supply Association vs. FERC* (EPSA, 2014) the U.S. Court of Appeals for the D.C Circuit injected uncertainty into the future of demand response (DR) resources in U.S. wholesale markets. Among several things, the decision explicitly identified "incentive-responsive demand" as a retail transaction, not a wholesale transaction. Thus, demand response, as the industry has come to understand it within the confines of Independent System Operators' and Regional Transmission Organizations' (ISO/RTO) administered energy markets, is not under FERC jurisdiction but rather state jurisdiction. However, if the Court of Appeals' majority arguments are taken to their logical conclusion, then FERC may not have jurisdiction over DR providing any bulk-power system service, not just energy.

This is exactly the conclusion FirstEnergy Corp. espoused when, on the same day the D.C. Circuit Court panel issued its *EPSA* opinion, the utility filed a complaint with FERC requesting that the federal regulator require the removal of all of PJM Interconnection's tariff provisions regarding DR in its capacity markets (FERC, 2014a). New England Power Generators Association (NEPGA) followed suit in mid-November asking FERC to order ISO New England to exclude DR resources from the region's Forward Capacity Market (FERC, 2014b). Both FirstEnergy and NEPGA are not just asking for DR to be excluded from future participation as a directly compensated resource in wholesale capacity markets, but that *all* existing ISO/RTO capacity contracts with DR resources become null and void.

The legal fight over FERC Order 745 and the D.C. Circuit panel's decision is set to continue, as the U.S. Solicitor General on January 15, 2015, filed a petition for review of the lower court's decision in *EPSA* to the U.S. Supreme Court.

While the courts and parties will continue to weigh in on a distinction between retail and wholesale markets, DR is a resource that does not concern itself with such boundaries. Furthermore, what is being played out in the courts has serious implications for DR and all the benefits it provides electricity systems, and consumers, chief among them helping to keep electricity costs down and the lights on during system emergencies.

Yet, given the uncertainty surrounding how FERC and the federal courts will rule on the various matters before them on this topic, certain affected states run a risk of experiencing a drop in reserve margins and resource adequacy, and a commensurate rise in market prices in the intervening period between DR being excluded from direct participation in wholesale capacity markets should FERC or the courts rule as FirstEnergy and NEPGA have asked, and when state-driven retail DR capacity programs can ramp up as necessary to address this disruption.

Many possible future scenarios in which DR continues to be available to provide capacity for resource adequacy would need to rely on a potential checkerboard of policies promulgated by state utility commissions. However, the states that will be most directly impacted by the potential implications from the *EPSA* ruling are precisely those that have the fewest policies currently in

place to promote retail program development. Many states in the Eastern ISO/RTO footprints (i.e., NYISO, ISO-NE, PJM) seem to have made a decision at the advent of ISO/RTOs to let the market dictate DR resource type, size and compensation – consistent with decisions many states made in the prior decade to unbundle generation from transmission and distribution assets. As a consequence of such decisions, many of these states overwhelmingly rely on entities that act as a customer’s agent. Called Aggregators of Retail Customers (ARCs), these entities subscribe customers to provide demand-response resources in the ISO/RTO DR capacity market.

If ARCs, and to a lesser extent utilities and end-use customers themselves, are no longer able to directly enroll in ISO/RTO DR programs and be compensated through such programs for their efforts, state regulators and policymakers will need to determine two key issues:

1. Who should be responsible for the administration of retail demand response programs?
2. What role should agents (i.e., ARCs) play in developing DR resources for participation in retail DR programs?

The answers to these questions will have a distinct impact on: what types of programs are offered by the administrator; what compensation system is used and by whom; and how the risk of non-performance is addressed and shared among the program provider, agent and participating customer. The detail and promptness with which regulators answer these questions and enact enabling policies will dictate the impact of the court’s decision on resource adequacy and electricity costs in the short-run and the eventual size of the DR market that develops in the long-run.

Below we review the brief history of demand response and suggest various options policy makers may consider for continuing to take advantage of this valuable resource.

2. Evolution of DR as a Capacity Resource in Organized Wholesale Markets

Before the advent of ISO/RTOs, many utilities offered interruptible/curtailable rates for larger commercial and industrial customers, as well as direct load control programs for smaller mass-market customers (i.e., residential and small commercial). These rates and programs were intended to contribute primarily to resource adequacy and were valued under an administratively-determined avoided cost framework. With the introduction of wholesale capacity markets managed by ISO/RTOs, the ability for these utility administered rates and programs to capture the value they provided was uncertain and thus their viability was in question. In order to retain access to these resources when the ISO/RTO went live, ISO/RTO administrators, working with stakeholder groups, created wholesale demand response programs which would treat participants as supply-side resources, to the extent feasible. PJM’s Active Load Management and NYISO’s Special Case Resources were two such examples of this effort.

In response to these new wholesale market DR opportunities, state regulators had a choice to make. They could take advantage of the power and market signals provided by organized markets to innovate by allowing agents to subscribe customers to ISO/RTO programs, recognizing that they

would have a profit motive to provide novel offerings that might be more successful than utilities at developing DR resources. Or, state regulators could continue relying on utilities to provide their own programs and be the sole entities that could act as a customer agent for participation in the ISO/RTO programs.

Regulators in some states within ISO/RTO footprints chose the first path by allowing ARCs to directly enroll customers in wholesale DR programs, while setting guidelines for how regulated utilities needed to operate their own programs. For example, in New York State, the regulated distribution utilities were initially required by the Department of Public Service (NYDPS) to pass along 90% of all NYISO DR program incentive payments and 100% of any assessed non-performance penalties to participating customers (NYDPS, 2000). ARCs, on the other hand, were allowed to negotiate directly with customers the terms of participation in the NYISO's DR programs, resulting in the aggregator retaining more of the program payment while shielding participants from any risk of non-performance.

In other states, utility concerns about third parties affecting the level of utility retail sales resulted in regulators prohibiting ARCs from directly subscribing customers to ISO/RTO DR programs. For example, the Indiana Utility Regulatory Commission (IURC) prohibited ARCs, leaving utilities in charge of bringing DR resources to the PJM and MISO wholesale markets (IURC, 2010). According to joint testimony filed in the proceeding, the utilities were concerned about "transparency" -- having visibility into customer loads to be served absent curtailment in order to determine accurate energy, capacity and reserve requirements.

Although the DR programs offered at the retail and wholesale level have different rules and participation requirements, each can affect the timing and level of electricity consumption and hence resource adequacy. On the retail side, utilities have historically relied on direct load control and interruptible/curtailable program offerings. Such DR opportunities can be highly effective at achieving sizable aggregate peak load reductions, but only to the degree that utilities successfully offer and market DR programs. For example, according to the 2012 Demand Response & Advanced Metering survey (FERC Survey) data, Indiana utility DR programs have the potential to reduce the state's peak demand by ~2.5% while Wisconsin can achieve ~6.5% peak reduction with its utility DR programs. This range of peak load reductions is roughly comparable to what has been observed in ISO/RTO jurisdictions that allow DR resources to directly participate as capacity resources in the market. The 2012 FERC Survey data also indicated that ISO-NE has the potential to reduce its peak demand by ~4% with its Emergency and Capacity as a Load Resource programs, while the NYISO has enough DR resources to potentially reduce system peak demand by ~7%.

Recently, utilities have begun to expand DR opportunities for residential and small commercial customers that take advantage of their smart meters' capabilities. In the former case, these have generally taken the form of critical peak pricing rates or critical peak rebate (also called peak-time rebate) programs. Baltimore Gas and Electric, for example, began defaulting residential customers with smart meters onto a critical peak rebate program in 2013 as a way to engender greater DR participation across its service territory. Regulators were willing to support such a broad-based rollout in part because the utility had four summers of experience with a similar pilot program.

Furthermore, customers only get paid if they reduce consumption below their calculated baseline, so participation is construed as a risk-free opportunity for eligible residential customers. During the summer of 2014, more than 819,000 customers were eligible to participate in Baltimore Gas and Electric’s (BGE) two declared emergency events. According to a company presentation at the 2014 E-Source Forum, there was a 76% average participation rate in these events, resulting in an average bill credit of \$6.55 per customer for a total of ~\$5M in payments to customers (Kiselewich, 2014).

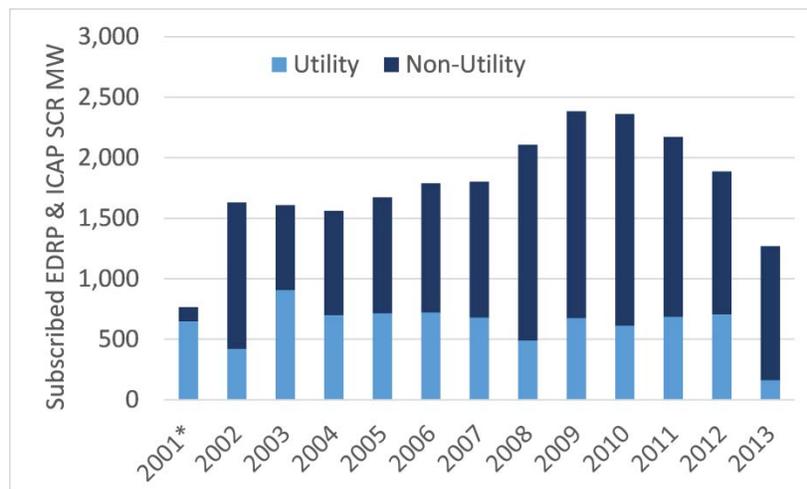


Figure 1– Subscribed Curtailable Load to NYISO EDRP and ICAP/SCR Programs.

* Extrapolated value based on reported data.

With respect to larger customers, advances in automated demand response approaches targeted at commercial, institutional and industrial customers has opened up opportunities for better and broader demand management that can be utilized by several different industry organizations. For example, since October 2011, the Demand Response Research Center at Lawrence Berkeley National Laboratory and New York State Energy Research and Development Authority have conducted a demonstration project enabling Automated Demand Response (Auto-DR) in large commercial buildings located in New York City using Open Automated Demand Response (OpenADR) communication protocols (Kim et al., 2013). In particular, this project focused on demonstrating how OpenADR can automate and simplify interactions between buildings and various stakeholders in New York State including the independent system operator, utilities, retail energy providers, and curtailment service providers.

In spite of this expansion of utility time-based rates and incentive-based programs as organized wholesale markets have developed over the past 15 years, utilities in many states increasingly became minor players in the DR business, as ARCs took on the role of customers’ agents. ARCs focused their marketing and recruitment efforts on those ISO/RTO DR programs with fixed up-front payment provisions and an obligation to curtail when called to a committed load reduction level (capacity market programs) over those with payments for voluntary load reductions in response to high energy prices (energy programs). Utilities, on the other hand, didn’t market either program nearly as heavily. As a result, ARCs rapidly increased their market share. In New York,

according to annual FERC demand response program filings, ARCs provided only about 15% of the DR capacity in the first year (2001) that the NYISO offered Emergency Demand Response Program (EDRP) and Installed Capacity Special Case Resource (ICAP/SCR) programs, but by 2013 ARCs were providing 87% of the DR capacity (see Figure 1). The story is similar in PJM, where ARCs currently provide 77% of the DR capacity (PJM, 2014).

This experience suggests that in jurisdictions where ARCs acting as customers’ agents to subscribe customers to DR programs have been allowed to flourish, traditional utility load management programs have generally languished. Conversely, in jurisdictions without such opportunities, traditional utility load management programs (i.e., direct load control and interruptible/curtailable tariffs) have continued to thrive. According to the 2012 FERC Survey, over 85% of the potential peak load reduction in the NYISO and ISO-NE regions is attributable to ISO/RTO program offerings classified as Emergency Demand Response or Load as a Capacity Resource. In MISO’s footprint, the lack of an organized wholesale capacity market and any associated DR program severely limits ARCs opportunities such that 99% of the potential peak load reduction comes from traditional utility load management programs (see Figure 2).

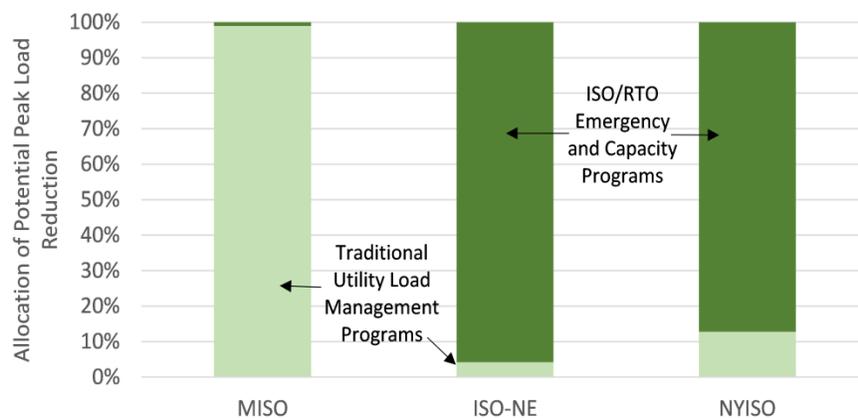


Figure 2 – Allocation of Potential Peak Load Reduction by Program Type

3. FERC 745 & DR as a Capacity Resource—Another Crossroad for State Regulators?

If the D.C. Circuit Court panel’s *EPISA* decision is upheld and the FirstEnergy and NEPGA complaints are all affirmed, then ISO/RTOs will likely be forced to halt paying demand response for providing any bulk-power system service (i.e., energy, capacity, ancillary services). This could have implications for the level of demand response available for bulk power system reliability. As Figure 2 shows, such a situation could mean ISO-NE and NYISO would see DR resources available for resource adequacy drop to 5-15% of their current levels in the near term.

Without ISO/RTO programs to create value from DR as a bulk-power system resource, utility regulators will find themselves at another crossroad. Based on more than 15 years of experience with ISO/RTO programs, state regulators should now be considering how best to fill the void that

may be created in the wake of these legal proceedings. Specifically, who will be tasked to administer DR programs (utilities vs. third parties), and what role will customer agents like ARCs have in bringing DR resources forward to participate in these programs?

Who will be the program administrator?

Since the advent of ISO/RTOs, several states have gained considerable experience with a variety of different program administration and implementation models for energy efficiency (e.g., New York, Oregon, Vermont, Hawaii) which could serve as a starting point for their application to demand response programs.

One option is for the utility to retain ultimate responsibility for the portfolio of DR programs but “outsource” the administration and/or implementation functions of certain programs to a third-party. Under such an approach, the utility is directed to develop a competitive solicitation that presents the roles and responsibilities of this entity, which can include program management, design, marketing, equipment procurement and installation, equipment maintenance, dispatch communication, and customer service. The solicitation may also include details about the program, such as availability of DR resources as well as measurement and verification methodology. Some solicitations might include an explicit quantity of demand response that the bidders must commit to delivering and maintaining within a certain period of time as well as what types of resources are acceptable (e.g., on-site generation, direct load control, etc.).

Currently, many utility DR programs have a variety of implementation functions outsourced to third parties. For example, Comverge was awarded a contract in 2009 to provide services for the Pepco and Delmarva Power’s direct A/C load control program including hardware, software, installation and program management, while assisting the utility with marketing and customer enrollment effort (BusinessWire, 2009).

It is much rarer, however, for the entire program to be outsourced. As an example, in 2008, the Colorado Public Utility Commission (COPUC) ordered Xcel Energy (Public Service of Colorado) to issue an RFP for third-party demand aggregators to administer the utility’s Peak Savings DR program (COPUC, 2008). EnerNOC, a large aggregator, signed an 8-year deal in 2009 to be the exclusive program administrator and implementer.

An alternative approach for state policymakers is to directly pursue a third-party to administer and/or implement the entire DR program portfolio. Under this model, such third-parties could be an existing state agency, whose scope of responsibilities is thus expanded, a for-profit or nonprofit entity (e.g., Vermont Energy Investment Corp.) selected through a competitive process, or establish a new nonprofit entity to act as the program administrator. Although the authors are not aware of any state that has chosen either approach for demand response to date, there is experience in the U.S. with state agencies or for-profit/non-profit entities administering energy efficiency and renewable energy programs. New York, for example, has repeatedly expanded the scope of the New York State Energy Research and Development Authority (NYSERDA) over time to include not just energy efficiency but also renewable energy program offerings and others that provide financial support for enrollment in the NYISO’s demand response programs (e.g., incentive

programs to fund meter upgrades). In Oregon, the Public Utility Commission created a non-profit corporation (Energy Trust of Oregon) to be the state's administrator of energy efficiency and certain renewable energy programs under a grant agreement. In some cases, the scope of activities could conceivably be expanded to include demand response program offerings.

Who will be allowed to enroll customers?

Regardless of who is retained to provide program administration services, states have options concerning who could be responsible for inducing customers to participate in such programs.

The dominant model in the retail sector at present is for the entity responsible for program administration to be the entity responsible for filling the program with customers. In most jurisdictions, the utility is administering the DR program and thus has the responsibility to recruit and compensate customers who participate. However, in some cases, the third-party who provides program administration also has an obligation to meet specific load reduction targets under a "pay-for-performance" type contract. For example, in the Xcel Energy Peak Savings program, EnerNOC is contractually obligated to enroll enough customers to provide 44 MW of peak demand reduction from the utility's commercial and industrial customers.

Another retail DR program enrollment model, consistent with today's ISO/RTO programs, would allow agents of electricity customers to come forward with DR resources because there is an opportunity for the agent to be compensated for doing so. Under this approach, either the customer or its authorized agent (i.e., an ARC) could enroll the customer in the utility's or third party's DR program. The customer's agent could choose, as many ARCs currently do for customers' enrolling in ISO/RTO programs, to shield the customer from any non-performance penalties the utility may levy against its assets. As payment for its services and accepting this additional risk, the agent would negotiate with the customer an acceptable sharing of the fixed and/or variable payments the DR program provides. The agent might also provide some form of enabling or automated control technology as part of the package to increase the level of DR provided to the program administrator. In the end, the agent would be responsible for verifying and validating that each of its resources have met whatever program rules the program administrator has developed that apply to directly participating customers.

As an example, the Indiana regulatory commission in 2011 approved Indiana Michigan Power Company's (I&M) tariff filings to allow customers, as well as their agents, to participate in the utility's demand response program offerings (IURC, 2011). The experience since this opportunity was made available illustrates that aggregators can adapt their business model in order to become adept at enrolling customers under such an approach. Based on an October 31, 2012, DR compliance filing, aggregators had enrolled more customers (8 entities representing 34 utility accounts) into I&M's emergency/capacity DR program (D.R.S.-1) after roughly a year than the utility (7 entities representing 19 accounts).

4. Conclusions

If FERC ultimately approves or is ordered by federal courts to grant FirstEnergy's and NEPGA's request, the vast majority of DR as a capacity resource may disappear overnight in PJM and ISO-NE absent state efforts to rapidly expand retail program offerings. Whether the decision is extended to all other organized ISO/RTO markets is also possible.

In anticipation of this potential outcome, some ISO/RTOs are creating contingency plans. PJM drafted a white paper in October 2014 laying out its vision of alternative DR opportunities in a post-Order 745 world. NYISO also has posted a draft plan. ISO-NE has largely put on hold its planned market rules and software changes to comply with Order 745 until the courts or FERC resolve the matter.

Most states, however, do not seem to be pre-emptively strategizing or undertaking contingency planning to mitigate the potential effects of the appellate court's decision on Order 745. Nonetheless, they may find themselves at yet another key decision point, similar in many respects to one they faced roughly 15 years ago – determining who should be responsible for bringing forth demand response resources: the market or utilities. New York may be one of the only examples of a state currently looking to substantially expand the role of its retail distribution utilities to administer a series of DR programs that could be used at both the distribution as well as bulk-power system level (NYPSC, 2014). This effort is but part of New York's much more comprehensive "Reforming the Energy Vision" proceeding. Thus far, the proceeding has expressed support for allowing both direct customer participation as well as participation through customer agents like ARCs.

The necessary policy changes to support such expansion of retail demand response programs in jurisdictions that have relied on wholesale programs for the past 15 years won't happen overnight. Many states in ISO/RTO jurisdictions have allowed their utility load management programs to languish, so enabling policies, program rules, and administration efforts will take time to get up and running. In the intervening period, depending on reserve margins, reliability could be jeopardized and electricity prices could rise. The sooner states begin the process of determining how to get that demand response back as quickly and efficiently as possible, the smaller the disruption will likely be.

One possible way forward for states to consider is to enlist a broad base of perspectives to come up with potential solutions. State regulators could consider collaborative processes with utilities, aggregators, key stakeholder groups and policymakers. The goal of these collaborative efforts would be to identify the single best option or a suite of preferred options for making DR resources available, both as part of contingency planning in the event of lengthy legal proceedings, or as a way for states to proactively take greater control over DR resources.

Given the U.S. Solicitor General's request that the Supreme Court to review the appellate court's *EPSCA* decision, resolution of the issues concerning the role of demand response in wholesale market will take time. State regulators and policymakers should make the most of this time to

develop contingency plans to ensure resource adequacy is not jeopardized and to ensure that DR remains a robust resource for meeting electricity needs at least cost.

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