Curtailment Service Providers: They Bring the Horse to Water… Do We Care if It Drinks?

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ABSTRACT

Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) are increasingly turning to demand response as a strategy for meeting load obligations and solving specific geographic congestion or reliability concerns in the existing distribution network. One approach is to engage curtailment service providers, commonly referred to as aggregators, to market demand response, identify curtailable load, enroll customers, manage curtailment events, and calculate payments or penalties for their customers.

This paper discusses the findings of a process evaluation of three aggregator-driven demand response programs in California that rely on aggregation firms. The process evaluation found that while aggregation firms bring expertise in identifying and recruiting customers for demand response curtailment, the diffuse and opaque nature of the relationship between aggregators and their customers makes it difficult to understand the experiences of their customers. Without this information program sponsors are unable to determine:

- If customer experiences with aggregation firms are turning them away from program engagement
- What program components seem to lead to success in meeting demand response targets
- If capacity payments are greater or less than required to entice demand response commitment

Process evaluation surveys can reveal participant motives, their understanding of curtailment, and illuminate the specific actions they take or plan to take when called to reduce their energy use. To be effective, however, these surveys require that: (1) aggregators are able to provide a contact name for each site; (2) post-event surveys are conducted immediately after a demand response event; and (3) interviews can be linked to specific site performance.

Introduction

The California IOUs offer a variety of programs covering all aspects of demand response. Each utility offers a portfolio of demand response programs that includes both reliability and price-responsive programs. Reliability programs are used to mitigate risks to the system due to high-demand, load instability, or transmission and distribution constraints. These programs include direct load control, emergency, and capacity programs. Reliability programs often pay retainers to customers who make themselves available to drop load when called to do so. A penalty may be levied in situations where requested curtailment does not materialize. Reliability programs do not always compensate enrolled customers for the load they drop during a called event, particularly if the participating customers are provided on-going benefits through lower electricity rates in exchange for their enrollment.

Like reliability programs, price-responsive programs can include retainer payments for enrolled capacity, but may also pay a specific, established price per kilowatt hour curtailed for demand response. Penalties for nonperformance are typical, and may take the form of higher rates (in the case of dynamic rate structures or critical peak pricing) or in actual fines levied for nonperformance. These programs tend to be utilized when prices or demand are particularly high, thus serving as a hedge against volatility in the wholesale power markets. Past research has found that many utility representatives do not regard the capacity nominated through price-responsive demand response programs as a firm resource, but rather as a strategy for improving the overall efficiency of electricity markets (Hopper et al. & Engel 2006).

The process evaluation on which this paper is based included in-depth interviews with representatives of each of the three programs reviewed (Peters & Moran 2009):

- **The Capacity Bidding Program (CBP)** is a California statewide price-responsive program developed to succeed the California Power Authority's Demand Reserves Partnership program that ended in 2006. The CBP is a tariff program that provides specific payments to nonresidential customers who volunteer to reduce their energy use (load or capacity) by a specific amount for each month of the CBP season (May through October). The CBP first was implemented in 2007. This program was offered in the territories of all three electric IOUs in 2008.
- **PG&E's Aggregator Managed Portfolio (AMP)** allows aggregators to negotiate agreements with PG&E to deliver a specified amount of demand response for a price established in the contract. As negotiated bilateral contracts, the terms (both the level of demand-response capacity promised and the price paid for it) between PG&E and each aggregator can vary.
- **Southern California Edison's (SCE's) Demand Resource Contracts (DRC**) program procures demand response capacity through aggregators responsible for marketing the opportunity, identifying and enrolling eligible customers, notifying those customers of curtailment events, and reconciling payments for customers who curtail their energy use during events. The DRC program is guided by contracts negotiated between each aggregator and SCE. As in the AMP program, the terms (both the level of demand-response capacity promised and the price paid for it) between SCE and each aggregator can vary.

We also completed two sets of surveys with participants. The first survey contacted over 200 participants and covered a range of process issues, including communication and interaction with the program, expectations from participation, overall satisfaction with various components of the programs, and future demand response intentions. The second survey was a qualitative conversation with a subset of participants who had been previously categorized as consistent or *inconsistent* responders, based upon the load impact analysis completed by the impact evaluation team.

This paper is based on our experience conducting a process evaluation of aggregator-driven demand response efforts in California. The process evaluation was conducted in conjunction with impact work focused on measuring the load impact of aggregator-enrolled capacity during the summer of 2008. In all cases curtailment service providers recruited and aggregated eligible, but usually not-yet-participating, customers. These customers were then notified to curtail their energy use in response to requests by their aggregator. In all cases the notifications were triggered by the utility based on a previously established threshold price, or in the event that the utility experienced a generation heat rate of 15,000 BTU per kilowatt hour.

Enter the Aggregators

The participating aggregators represented a diverse group of energy service firms operating in California. In some cases, the organizations were California-based, in other cases they operated with multiple offices in multiple utility territories. Corporate headquarters were scattered throughout the nation.

Aggregation firms vary in size and focus and can include load-serving entities providing demand-response services to their existing power customers, firms whose primary focus is profiting from demand-response payments available throughout the nation, and vendors who profit from the sale of proprietary energy management or enabling technologies.

Individual business plans and market approaches among these firms tend to reflect differing relationships to enabling technologies. Our interviews found that firms encouraged the installation of technologies likely to meet their unique needs for visibility, monitoring, communication, and control. Some firms operate with centrally-managed network operations or communication centers that control participating providers' load and monitor performance. These firms tend to require participants to install monitoring and/or visibility equipment that allows for either automated curtailment (typically through an Energy Management System programming) or near real-time monitoring.

By promoting and managing curtailment activities, aggregation firms absorb the risk of underperformance. Instead of having to pay penalties for underperformance (as directly enrolled participants might), aggregators will withhold future payments to underperforming customers. In this way, the end-use customer will not find themselves having to write a check to the utility to cover their poor demand response performance—an abhorrent circumstance for most commercial customers. Aggregators are also expected to provide the technical skills required to estimate load and the communication capacity to trigger large-scale notification efforts.

Outreach and Recruitment

One of the most important advantages of engaging aggregators is leveraging their marketing expertise. In California, the three IOUs relied almost completely on aggregators to market these demand response programs to potential participants. Recruiting new customers can be challenging, particularly for aggregators engaged in unsolicited marketing activities (as opposed to those that only approach existing customers). As a third party, aggregators operate without access to load or meter data, rate class, or other indicators of likely eligibility prior to contacting a customer. Industry type and estimated load size are two common indicators of curtailment potential. These factors often reflect eligibility, but do not map perfectly to qualifying meters, nor do they tell aggregators which firms are already enrolled in a (potentially conflicting) demand response program. The portion of customers ultimately found to qualify can be quite low; contacts from aggregation firms interviewed provided estimates as low as 5 or 10%.

Aggregators will sometimes brand their program services so the program exists as a local version of demand response programs offered in other jurisdictions. Branded program names do not necessarily reflect the tariff or program name developed by the utility. Indeed, aggregation firms can bundle several program options under one brand and funnel participants into the appropriate program in a manner that is seamless and invisible to the customer.

Among aggregator firms that reported active recruitment and sales activities, contacts described using a variety of prospecting tactics to identify potential load providers. Typical scenarios involved a phone call or visit by an aggregator representative seeking someone able to answer basic questions about proxy indicators of potential eligibility, including revenue, number of employees, square footage, size of energy bill, SIC code, or rate class. These proxy indicators are often the only way to identify potential load because customers rarely know their peak demand by meter.

Once a prospect has been identified, aggregation firms report that customers have concerns about the effect of curtailment on their businesses, the number of potential events and the duration of those events. Potential participants also worry that they may not have load to provide, and that they might be penalized for underperformance. Aggregators must explain both the concept of demand response and the parameters of the program opportunity. Aggregators are free to offer protections to customers in terms of absorbing or deferring penalties, installing equipment and conducting curtailment tests.

Utility contacts were optimistic that aggregation firms were tapping into customers who had not already participated in demand response programs. Participant surveys confirmed this belief with over 75% of contacts reporting that their organization had not previously participated in demand response programs.

Assessing Response Status

For each program in each utility territory, the impact evaluation team used a regression model to the estimate total program-level load impacts for each program from estimates of load reductions for all sites nominated for events in any of the programs during 2008 (Braithwait Hansen & Armstrong 2009). This was done by measuring customers' actual usage relative to their baseline. Their usage was modeled to determine if usage during events was statistically different from their usage at other times. The impact evaluation team then used data from this model to identify the extent to which specific sites responded or failed to respond to curtailment events.

The process evaluation activities required linking the curtailment response estimates created by the impact team to specific contact names at actual sites, so that we could define consistent and inconsistent response sites. To do this, the process team worked with the impact team to categorize the level of response for each organization. The unit of analysis for the impact evaluation work was the service agreement identification. While a service agreement does not map perfectly to a qualifying meter, in this paper we use meter and service agreement interchangeably. The impact team applied a *strong response* label if load impact coefficient was significant, and a *mild/no response* label if it was not significant. To split our list into *consistent* and *inconsistent* responders for the purpose of the post-event survey, we categorized the impact team's strong respondents as *consistent responders* and the mild/no respondents as *inconsistent responders*. We then applied these categories to our own population list.

A process evaluation is focused on the experiences of the people involved, not the data tracked at a meter or account. Thus, the population of interest is the unique customer by name, not the status of a given site. However, since approximately 40% of the unique customers in the process evaluation contact list were found to have multiple meters enrolled, and thus had multiple service agreements, we had to develop a strategy for calculating the consistency status by organization, not meter. A single organization with numerous locations enrolled may have some sites that consistently perform and some that consistently failed to perform during called events. To categorize customers with multiple meters enrolled, we considered them consistent responders only if the number of *strong response* sites exceeded 50% of the total number of sites enrolled. For example, a customer with 20 service agreements was considered *consistent* if at least 11 of the sites were labeled *strong response*.

Finally, we merged the unique customer contact list with the curtailment response categories and load-size data by matching customer names. We were not able to link the contact name from the unique contact list to the impact evaluation files for 38% of the list. This is likely due to the fact that the lists originated from two different sources; the customer contact list originated from the lists provided to the process team by each aggregator; and the curtailment-response and load-size data originated from program settlement data provided by each of the three utilities. While theoretically these two lists should match, there are several reasons why customers in the process evaluation contact list might not appear in the impact evaluation list, and vice versa. One reason may be the inclusion of non-nominated or dropped customers in the aggregator-provided lists. Customer information for customers that had not actually been nominated or curtailed was likely removed from the impact analysis. Aggregators also could have failed to provide the process evaluation team with a complete customer list. Finally, a number of unmatched names are likely due to inconsistent tracking, misspelling, or other differences between aggregator-provided names and those existing in the utility customer information system. While we reviewed each list carefully and manually matched many names, it is possible we missed some number of matches because the contact name was completely different or the organization had multiple identities.

Our experiences with this categorization effort provide insight into how difficult it is to identify the relationship between specific people or organizations and load impacts—regardless of the statistical tools employed.

Findings

Our surveys found few significant differences between the reported experience and activities of the consistent and inconsistent responders; specifically:

- Consistent responders were significantly more likely to report possessing a specific action plan (96%) when compared with inconsistent responders (73%).
- Inconsistent responders rated the importance of knowing the reason for the curtailment request significantly higher than consistent responders.
- Inconsistent responders agreed at significantly lower rates than consistent responders with the following two statements: *"I had enough time to prepare for DR events." and "The number of DR events was what I expected."*

If the programs only paid for actual performance, this question might be moot—capacity not delivered isn't paid for. However, since many programs include a capacity payment for registering and nominating load regardless of whether or not it is activated, it is reasonable to expect that utilities would want to confirm that the capacity they are paying for truly exists. This is particularly true given the uneven nature of called events. For example, as Table 1 illustrates, in CBP the likelihood of being called to curtail in a given month varied widely, depending on the territory and demand response product registered for. SCE's day-ahead option was activated far more than were the other utilities'.

Table 1: Number of 2008 CBP Events by Utility

Utility: Notification Option	June	July	August	Sept	Oct	Total
PG&E: Day-Of	1	--	--	--	--	1
PG&E: Day-Ahead			1(Test)			1
SCE: Day-Of					2	2
SCE: Day-Ahead		5	8	4	3	20
SDG&E Day-Of					2	2
SDG&E Day- Ahead		2				2

Not every customer or every aggregator would have been called for every event, since these programs operate with a variety of portfolios that can vary depending on notification requirements and maximum duration.

SCE's Strategy: The Technical Potential Assessment

To mitigate the risk that enrolled load would not materialize if called, Southern California Edison established a technical potential assessment process for load enrolled through DRC, through which aggregators must document their enrolled curtailment capacity. In DRC, aggregators are penalized $4,000 for the first megawatt of missed load reduction and $1,000 for each additional megawatt of missed load reduction. Since penalties accrue with even one megawatt of missed load reduction, SCE developed a process for assessing the technical potential for the group of service accounts nominated each month by each aggregator. The DRC purchase agreements require aggregators to submit a written statement assessing the estimated kW demand reduction available for each service account within their aggregated group after providing a list of those customers for each operating month. Aggregators make this assessment by considering their customers' total demand, seasonality factors, individual curtailment plans, the level of automatic curtailment, the presence of enabling technologies, prior experience with demand response, and past performance. DRC staff reviews this technical potential assessment and evaluates portfolios.

The assessment document is checked for reasonableness through an iterative process of validation and discussion until it is approved. DRC staff believes the process of developing the technical potential document helps aggregators identify and account for aspects likely to affect their customers' load reduction capacity. These variables include the seasonality of the load or the reliability of automated curtailment systems.

The technical potential reports are considered a tool for identifying the actual load likely to be available, were an event to be called. Since DRC is a contract-based program in which aggregators are expected to have a certain level of enrolled megawatts by the beginning of the program year, technical potential documents provide tools that help DRC track capacity and avoid punishing aggregators for the length of time required to find eligible customers, close the sale, and enable the capacity. Because firms are contractually obliged to meet their kW load requirement, the technical assessment process can be used to lower the expectations (and corresponding payments) for aggregation firms still enrolling customers. Performance during test events creates a baseline for the performance of each aggregated portfolio, and identifies areas where the aggregator was weak. In some cases, aggregators were unaware of these weaknesses. When test results come in noticeably below the level indicated by the technical potential, staff re-review the assumptions and capacity in a given portfolio.

For months in which no event is called, if the technical potential assessment is less than the capacity contained in the contract, the delivered capacity payment is adjusted downward to equal the technical potential times the capacity credit rate. However, if the technical potential assessment is greater than the contracted capacity, the delivered capacity payment is not increased.

For months in which an event is called, the capacity payment calculation is based on the *measured* performance of the aggregated portfolio, not the technical potential assessment. However, any difference between measured performance and the technical potential assessment is taken into account in reasonableness reviews of future technical potential assessments.

The process of assessing and reviewing the technical potential associated with each aggregated portfolio is not an explicit part of the DRC contracts, but current aggregators have agreed to the approach, including any reductions in expected load impacts and corresponding settlement payments resulting from a technical potential assessment lower than the contracted capacity. SCE expects to amend the existing agreements to include this process for the 2009-11 program.

Enrolled Load: Who Are They and How Are They Enabled?

Participant organizations span a wide range of business activities. The most commonly reported types of industrial activities reported were manufacturing and food processing. Retail, lodging, warehouse, and office buildings were the most frequently reported commercial activities. Thirteen percent of the participants reported their facilities were government-owned, including numerous water and wastewater facilities.

Sixty percent of surveyed participants reported their facilities did not have an energy management or building control system prior to their enrollment with their aggregator. Fifteen percent of participant contacts (40 of 267) reported <u>they had installed</u> new equipment in order to participate in the aggregator's demand response program and were able to describe it. The most common type of equipment installed was meter-based equipment that made it easier to monitor demand or allowed real-time consumption monitoring. This was followed by miscellaneous internal equipment and upgraded energy management systems that improved control.

Forty-two percent (96 contacts) reported that <u>their aggregators had installed</u> new technologies in their facilities, typically after their enrollment (88 of the 96).

Table 2: Aggregator Installed Technology (N=238)

New Technology Installed	AMP (n=83)	CBP (n=113)	DRC (n=42)	total (n=238)
Yes	27%	36%	88%	42%
No	73%	64%	12%	58%
Weighted Total	100%	100%	100%	100%

Note: Weighted percentages.

Respondents participating in Edison's DRC program were significantly more likely to report that their aggregators had installed technologies in their facilities compared with participants from other programs. Eighty-eight percent of DRC respondents said their aggregators installed some type of technology, compared to 27% of the PG&E AMP respondents and 36% of CBP respondents.

There are several potential explanations for this difference.

- First, in 2008 Edison installed IDR meters and PIB boxes for less than half the cost of similar installations at PG&E ($950 at Edison for both as opposed to $2,700 for an IDR only at PG&E).
- Second, Edison offered a path through which smaller commercial customers (down to 50 kW) could obtain an IDR meter for free.[1]
- Finally, DRC has a technical potential assessment process that requires aggregators to demonstrate exactly how much capacity will be available. The program also assesses performance penalties after the first missed megawatt—which may increase the desire by DRC aggregators to accurately manage their nominated capacity.

Table 3 summarizes the type of equipment that the respondents reported their aggregators had installed. In general, it was difficult for participant contacts to precisely report the equipment installed. Thus the categories below should not be viewed as an accurate description of what was ultimately installed. Rather, these categories reflect how participants *describe* what was installed.

Table 3: Type of Equipment Installed by Aggregator (N=99)

Equipment	AMP	CBP	DRC	Total
Meter Equipment	55%	**85%***	56%	68%
Monitoring Hardware/Software	**50%***	20%	**43%***	35%
Sub-Meter or PIB	10%	19%	**39%***	24%
Communication Equipment	10%	5%	19%	11%
Control Equipment	0%	14%	5%	8%

Weighted percentages. Multiple responses allowed; percentages will total to more than 100%.
*Differs significantly by program (X2, $p < 0.05$).

Experience of Load Providers

Ninety percent of participant contacts (230 of 255) reported receiving a notice to curtail because of an event or test event in 2008. The 10% reporting that they had not received event notification could have been from organizations enrolled later in the summer or excluded from nomination for some reason. Contacts could also be mistaken.

Almost sixty percent reported being called to curtail only one or two times in 2008. AMP and DRC contacts reported more frequent notification than did CBP respondents; within CBP participants, SCE customers reported significantly more notifications as compared with customers of PG&E and SDG&E. This is consistent with the number of actual events listed in Table 4.

The participants who reported they had received at least one event notification in 2008 were asked to describe potential improvements to the notification process. Only 30 offered suggestions for improvement. (Table 5) Earlier notification was the most common suggestion (given by 17). This was followed by: contacting additional/alternative contacts when the primary

[1] PG&E provided IDR meters at no charge to the customers of SF Power, as directed by the CPUC.

contact person is unavailable; phone calls in addition to email; ceasing additional notification calls once the aggregator has received confirmation; and considering time-zone issues, in cases where the corporate contact is located in other time zones.

Table 4: Number of Curtailment Events

Number of Times Called	AMP (n=78)	CBP (n=85)	DRC (n=34)	total (n=197)
1 to 2 Times	52%	73%	47%	**59%**
3 to 4 Times	35%	17%	44%	**28%**
5 to 9 Times	8%	8%	3%	**7%**
More than 10 Times	5%	2%	6%	**4%**

Table 5: Potential Improvements to Notification (Multiple Responses Allowed)

Suggestion	Weighted Count (N=30)
Earlier Notification	17
Backup Contact Information Available	4
Notification By Phone Not Only Email	4
Not Too Many Calls After Confirmation	3
Call In Appropriate Time Zone	2
Additional Email Notification	2

In order to understand why participants might appear to have failed to respond to an event and why some events failed to produce the nominated capacity, we asked participants if they perceived that responding to an event was ever optional in 2008. Surprisingly, more than three-quarters believed that their response to the curtailment request was optional. We found no difference between programs or utility territory, indicating a widespread perception among participants that they do not necessarily have to curtail when called. It is not clear whether this is communicated to them by their aggregator, or if the aggregators are unaware of this perception.

Response and Curtailment Activities

Almost all of the participants that recalled an event notification (205 of 212) reported taking action in response to the event notification. All consistent responders reported taking action in response to an event notification, while 10% of the inconsistent responders reported they did not take action. It is important to note that this means 90% of inconsistent responders did report taking action, but for whatever reason (lack of automation, lack of load to curtail, competing business demands, or variable performance between sites) their performance as reported in the impact evaluation data files indicated that their overall response was inconsistent.

Most of the 205 contacts who reported taking action reported doing so by manually shutting down equipment. This was followed, somewhat distantly, by manually launching an automatic curtailment system or program. Lowering lighting levels was the most common approach to meeting curtailment obligations, followed by increasing set points on air conditioning equipment and shutting down motors or other industrial processes.

Participants were asked if they knew why they had been asked to curtail in 2008. Almost half reported they believed they were responding to grid reliability issues, with a subset specifically mentioning avoiding brownouts and rolling blackouts. (Table 7) The perception likely imminent outages is consistent with previous market assessment work that found potential participants would consider enrolling in California demand response programs to lower their energy bills and *help mitigate power outages* (Rufo, Buege & Ting 2006). Similarly, an evaluation of a day-ahead bidding program operating in New York in 2002, found that many of the customers that rejected the bidding program participated another program providing short notice of curtailment obligation and significant penalty if the obligation was not met. In this case, the authors speculated that participants saw themselves as responding to system emergencies which provided "psychic income" from acting as a good citizen and reflected a rational reaction to the possibility of forced outage (Neenan, Bernie et al. 2003).

Table 6: Equipment Curtailed (Multiple Responses Allowed)

Type oF Equipment	Weighted Count	Weighted Percent (N=172)
Lighting	122	71%
Air Conditioning	92	54%
Motors	81	47%
Industrial Process	67	39%
Refrigeration or Freezer	15	8%
Elevators	4	2%
Compressor	4	2%
Computer Equipment	4	2%
Water Pump	4	2%

Note: Percent mentioning total more than 100 because multiple responses were allowed.

Table 7: Perceived Reason for Curtailment (N=214) (Multiple Responses Allowed)

Reason	Number	Percent
Grid Reliability Issues*	102	48%
Temperature or Weather-Related Demand	62	29%
High Price of Power to Utility	36	17%
Vague Comments; General Conservation	24	11%
Environmental Concerns	24	11%
Don't Know	15	7%

*Includes avoiding brownouts or rolling blackouts, protecting the grid and easing grid strain. Twenty-nine contacts specifically reported they had been asked to curtail to avoid brownouts or rolling blackouts.

Post-Event Surveys Reveal Flaws in Categorization Effort

The post-event surveys were designed to allow an interviewer to probe more fully into the actions taken or not taken during actual events in 2008. The team completed interviews with 24 participants during April and May 2009. We were able to complete more interviews with consistent responders than with inconsistent responders.

The goal of the post-event customer survey was to gain greater understanding of participants that seemed to consistently reduce their energy use when requested to do so by their aggregator in 2008. We had planned to conduct these interviews immediately after a curtailment event when memories were fresh and any impacts of curtailment could be recalled. Delays in project launch precluded immediate contact. Instead, we sought to conduct interviews with a sample of customers in each program, based on whether they had been found to have consistently or inconsistently responded to events.

Overall, this strategy for assessing the difference between consistent and inconsistent responders did not produce the level of detail we had sought in terms of understanding exactly what participants did when called to curtail and their experience of the event. We were unable to link a specific contact with a specific event in a meaningful way and were forced to rely on participant memories of events that could have occurred more than six months previously.

We found no differences in how consistent and inconsistent responders answered questions related to setting load reduction goals, their experience of event notifications, and their methods for tracking demand response performance. However, participants rarely reported keeping records of their curtailment activities, instead relying almost exclusively on information from aggregators to assess their curtailment accomplishments.

Participants required few staff to implement their curtailment activities; the majority reported having one to three staff directly involved in coordinating demand response events. All contacts reported that they communicated internally about events, with about half notifying their entire staff.

While only a few contacts reported it was important to be informed of the reason for the curtailment event, most assumed that they knew the reasons for their 2008 events. Communicating the reason behind the demand response event could help participants needing to enlist the cooperation of others – including those that try to communicate the event to large groups of students, staff, or customers. There are indications that participants may be attempting to forecast demand response events in advance of notification from their aggregators by monitoring utility information.

Conclusions

While the impact team was able to identify load impacts associated with the curtailment events analyzed for 2008, there are a myriad of reasons why aggregator-enrolled capacity could fail to materialize during a curtailment event. Weather-dependent load might not be available on a cool day, communication protocols could be inadequate, curtailment plans could be vague, or other business priorities could take precedent. Customers could have been gambling that they would not be called to curtail, or they could be planning to participate in the future, but not yet be prepared or enabled to do so. Aggregator staff could be employing optimistic estimates of technical potential, have ineffective notification protocols, or experience inconsistent response at end-use load providers they thought were reliable.

Program sponsors are unaware of promises made to customers by the aggregation firms that recruited them. They are also unaware of performance goals established for each customer, and are unaware of how the demand response obligation is communicated. Our finding that more than three quarters of respondents believed their curtailment was optional is but one example of why nominated load could fail to materialize when called.

It could be that the goals match the nominated load for each meter, but aggregators paid for capacity nomination have a strong incentive to over promise, and hope they are not called. SCE’s technical potential assessment process represents one approach to minimizing the risk in this scenario, and test-events can reveal lower than expected capacity. However, neither of these approaches can explain why organizations are able or unable to meet their obligations.

Participant surveys and process evaluation efforts are an obvious way to do this, but requires that aggregators or utilities are able to link a specific contact name with each enrolled meter, that load impact analyses link discernable curtailment to each meter, and that consistent and inconsistent responders are contacted within two weeks of an event, when memories are fresh and the activities launched (or not launched) can be recalled.

Given the challenges of identifying and assigning contact names to a consistently performing service account, our approach may not have identified all of the differences between these two groups. If it is important to understand the factors behind consistent or inconsistent demand response, utilities will have to require more detailed information from aggregators—specifically, what type of load is expected to be dropped and how the aggregation firm will know if this is occurring.

So… who should care if this horse drinks?

- Ratepayers should care, since they are paying to avoid future construction costs and high market prices. Participant responses might indicate that capacity payments are greater or less than required, that participants do not understand their obligations, or that they are motivated more by community concern.
- Utilities should care, since in most cases these are their customers. Surveys can confirm that customers understand what they are doing and could reveal whether or not customer experiences with aggregation firms are causing them problems.
- System operators should care, since this load is packaged and sold as a resource. Penalties may accrue for load curtailment not delivered, but at what cost to the grid?

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