Utilities and the Future: Utility Virtual Power Plant development and integrated M&V

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ABSTRACT

Utilities across the country are looking to Virtual Power Plants (VPPs), usually defined as dispatch of multiple distributed energy resources (DERs), to reduce emissions, generation costs, and infrastructure investments. A challenge for these systems is coordinated dispatch across a suite of load flexibility technologies. In response to this challenge, Puget Sound Energy (PSE) has built a complex system for its new and growing VPP. PSE collaborated with Autogrid to build a custom VPP interface for managing and dispatching DERs.[1] A partnership with Clean Power Research (CPR) allowed construction of a customized platform for automated customer lifecycle management. DNV is working with PSE to evaluate the first technology included in the VPP – a smart thermostat demand response program.

This paper describes pros and cons of this VPP approach, including reasons to pursue this type of platform for lifecycle management. It also addresses the challenges and strategies for coordinating with various technology manufacturers.

We discuss the challenges with the initial M&V and our evaluation approach. In addition, we describe the factors that influence event curtailment and how program administrators can best predict the curtailment from calling an event for a specific group of customers at a specific time.

This paper features lessons learned from building a VPP platform and evaluating its programs. These lessons are applicable for both thermostat and other types of demand response. Program administrators, delivery contractors, systems operations staff, and ISOs will all benefit from learning about the impact, reliability, and other successes and challenges of this VPP deployment.

Introduction

About Virtual Power Plants

Virtual power plants (VPPs), usually defined as the combination of distributed energy resources (DERs) to provide power to the grid, are becoming increasingly popular as a potential tool to serve growing load peaks and facilitate the transition away from fossil fuels (Downing 2023). VPPs are accelerating in acceptance, funding, and effort in the United States. In September 2023, the Department of Energy (DOE) published an article and report detailing the potential and barriers to widespread VPP operation, as well as opportunities for DOE to help develop VPPs (Downing 2023; Reed 2023). In early 2024, the Electric Power Research Institute (EPRI) and DOE agreed to study VPP deployment together (Maloney 2024). In early 2023, the Rocky Mountain Institute (RMI) launched a virtual power plant partnership to bring industry together to help VPPs grow (Martin 2023). In the last year, both the *MIT Technology Review* and *Forbes* have published articles focusing on VPPs (Kim 2024; King 2023).

[1] AutoGrid also acts an aggregator, providing customer and business programs across the PSE service area.

However, despite the recent focus on VPPs, the major DER aggregators' systems have been set up for single-technology dispatch. The majority of the VPPs in articles describing the technology are based exclusively on residential batteries; no other dispatchable DER is included in conjunction with these batteries[2]. These include Tesla's VPPs in South Australia, Texas, and California, as well as the Green Mountain Power and Mass Save battery dispatch programs (Government of South Australia 2024; Public Utility Commission of Texas 2023; Mass Save 2023; Just Energy 2023; Howland 2023). Businesses like OhmConnect, which gamifies peak residential energy savings to provide rewards, creates VPPs that control multiple smart home devices. However, instead of partnering with utilities, OhmConnect sells energy reductions directly to electricity markets, an approach that sometimes competes with internal utility demand response programs (Rayport 2023; OhmConnect 2024).

Puget Sound Energy's first VPP program

Like many other utilities, Puget Sound Energy is working to incorporate many demand-side resources – as a VPP – into its portfolio for serving its customers. Puget Sound Energy (PSE) seeks to meet multiple goals with this VPP. It has some communities with islanded distribution networks, which would face extremely expensive upgrades if load were to grow. This includes Bainbridge Island, whose limited distribution infrastructure is facing not only population growth and electrification of light-duty vehicles, but also the arrival of electric ferry service and associated charging. On a larger scale, PSE is required to comply with Washington's Clean Energy Transformation Act (CETA); to that end its Clean Energy Implementation Plan includes a suite of demand response (DR) programs, creating a VPP (Puget Sound Energy 2023).

The first VPP program PSE launched addressed infrastructure constraints for "islanded" communities – those with only one route (or very limited infrastructure) for energy delivery. Bainbridge Island faces this challenge on the electric side, while Duvall has gas infrastructure constraints[3]. In these communities PSE launched an initial smart thermostat demand response program in partnership with Autogrid. In parallel, PSE planned and has begun rolling out a suite of other demand management programs, including behavioral demand response programs, commercial and industrial demand response, time of use rates, water heater DR, and managed electric vehicle charging. After exploring implementer options for coordinating DERs in a VPP, PSE ultimately decided to build an internal customer lifecycle management platform and collaborate with Autogrid for a custom-built Virtual Power Plant interface to manage events for these programs.

In 2023 and 2024, DNV is evaluating PSE's demand response programs, including exploring pros and cons of the internal customer management platform/custom-built VPP interface and measuring program impacts. In this paper, we explore each of these topics.

[2] These batteries are generally paired with a residential solar system, but solar is not dispatchable and where solar is plentiful, it does not correspond with peak load, so batteries could equally help meet evening or morning peaks in a situation where the grid receives a large amount of large-scale solar. Batteries have generally been paired with solar because of investment tax credit requirements and/or because homeowners want the potential for self-reliance, not because the pairing provides peak grid benefits.

[3] While VPPs usually refer to aggregations of load curtailment on the electric side, PSE is also including some gas demand response programs in its VPP platform, so we use the term broadly in this paper to include curtailment of both electric and gas. (Though of course for gas it is not providing a virtual "power plant" but more of a virtual "gas distribution supply.")

PSE's Virtual Power Plant System

PSE has built an award-winning VPP system, used for the first time during the winter season of 2022-23 (Fortnightly 2023). We first describe this system, and then lessons learned from its operation.

VPP System Functionality

As described above, PSE decided to build an internal customer lifecycle management platform because they were unable to find a VPP vendor that incorporates customer lifecycle management capabilities in their platform offerings. In addition, it decided to work with Autogrid to create a custom-developed interface for managing multiple types of DERs, which had not previously existed. PSE is in a unique position; because it has not previously operated demand response programs, it is able to build up the platform and then incorporate new programs into it, making sure that they fit together. PSE's customer lifecycle management platform, jointly developed with Clean Power Research using their PowerClerk technology[4], includes functionality across all programs that:

- Manages customer enrollment and unenrollment.
- Checks customer eligibility for different programs[5].
- Updates data based on customer moves, meter replacements, and other program-impacting customer events.
- Communicates PSE-based enrollments/un-enrollments to program implementers and distributed energy device manufacturers.
- Updates customer tracking information based on enrollments that take place through implementer/device manufacturer platforms.

The custom-developed VPP interface that PSE and Autogrid built together allows PSE to:

- Call events for individual demand response programs and customers based on geographic and/or system needs.
- See predicted load curtailment for all programs scheduled for a specific demand response event.

PSE's internal management of customer enrollment and unenrollment allows it to keep as much customer data internal as possible, thus reducing data security risks. That is, to determine customer eligibility for these programs, PSE has to check customer enrollment requests against its internal database of all customers. This platform and approach minimize exposure of the internal all-customer database as it is not shared with program implementers. Only enrolled customer data is shared with the program implementers. The platform also allows for automation of the back-and-forth between enrollment (through the original equipment manufacturer (OEM), AutoGrid, or PSE interface), PSE verification, and implementer verification to ensure each entity's customer database is synced. Finally, the platform provides a solution for customer life

[4] PowerClerk is a highly customizable customer lifecycle management software that acts as a middleware between front-and-back-end systems
[5] Cross-checks with other DR program enrollments are currently done manually but will be incorporated into the platform this year

cycle management. That is, in addition to the enrollment data, the platform tracks unenrollment because of equipment failure, a customer move, etc.

The collaboratively developed VPP interface allows scheduling of demand response events by program and shows predicted total curtailment for the combination of all scheduled programs.

VPP System Lessons Learned

While the VPP system has provided extremely useful features, as described above, PSE has lessons learned from its creation that may be useful to others looking to build any parts of a VPP system. The needs that arose from these lessons learned include:

- Clear organization of stakeholders
- Clear timeline and goals
- Clear guiding principles document including specific VPP use-cases
- Well-staffed and consistent VPP team
- Willingness to be flexible

Below, we describe each of these in detail.

The first challenge in developing the VPP system arose from the number of stakeholders that needed and wanted to be involved with its design. VPPs have the potential to affect and provide value for many parts of a utility organization and are exciting new technologies; many people will be involved in the VPP development. PSE found that the number of stakeholders with different priorities make it more challenging to achieve a clear direction for creating the VPP system. For example, an early meeting on PSE's VPP was attended by thirteen directors.

A related challenge was a lack of a clear timeline and goals for the VPP platform. While some degree of ambiguity is unavoidable for developing a new system, the clearer the goals and timing can be, the easier development will be.

A clear and detailed guiding principles document, and one leader (with executive support) to champion that guidance and the direction of the VPP will mitigate these challenges. This document will create a vision for a system that has not existed before and for resources with which many utility staff may have limited experience.

The guiding document should include four one-year development cycles with clear phase gates per cycles. IT budgets should be clear for each of these development cycles. The document should also have a clear list of short, medium, and long term functionality requirements tied to development cycles and dictated by all impacted stakeholders, including but not limited to System Operations, Trade Floor, Load Office, Grid Modernization, Customer Record Management groups, Metering teams, New Product Development, Customer Support, and Customer Program teams.

Whether this information is included in the guiding document or elsewhere, project teams should document short-, medium-, and long-term use cases on a per-DER basis as they scope the project at an early stage. Documentation should also include a description of how a multi-DER environment works together, and how performance is evaluated for said DERs. The system should be designed such that the foundational VPP build-outs can support DERs plugging-into the system two or more years after VPP go-live. This documentation will allow stakeholders to have a unified and shared vision for the system.

This vision must also include a clear and agreed upon series of use-cases for practical applications of DERs used both separately and together, and how these DERs can be utilized on a per-use case basis: peak load reduction, market triggers, etc. Different DR use-cases are based on different event-call triggers, so the long-term plan must include prioritization of use cases and requirements and goals that matches use case priorities.

Even with the best possible documented program goals, new system build-out will always involve some level of ambiguity and learning-as-you-go. The team building the VPP should be composed of members who are comfortable with this kind of project. Team members should also be able to (to the best of their abilities) future-proof the project. However, they should also understand it is not possible to prepare for all future scenarios, so changes will be necessary as the project develops. Low staff turnover for this team can help provide continuity and adaptability in building this type of new tool.

Another challenge that PSE worked through in building this system was that it both needed to serve many utility departments and be customer friendly. To make sure both these goals are achieved, VPP project owners and stakeholders should be prepared to dedicate multiple full-time employees (FTEs) to supporting IT staff and providing guidance on practical customer program applications of VPP functionality. One way to achieve this would be in the form of customer program managers or journey managers. Furthermore, end-use customer experience should always be front of mind when discussing how various complicated internal systems interact with each other, and program owner sponsorship is critical in ensuring the product being built is one that can provide benefit to utility customers.

Finally, PSE has realized that its VPP system will evolve over time. ADMS, SCADA, and DERMS integration may be necessary to actualize many of the future state use-cases that are being discussed in the load flexibility industry at-large. There is no single solution to load flexibility challenges, and utilities must look holistically at how these various platforms interact and support each other to ensure utilities can support the growing demand for energy while delivering simple customer solutions at the program level.

As it continues to develop its VPP, PSE looks toward a future where its platform may also be able to include accurate impact estimates (for both gas and electric demand response), program-specific event impact predictions, and integration with how the resource will be considered on the market.

Evaluation of First Program Impacts

Program Details

As described above, DNV evaluated PSE's first program to be launched through its VPP platform, the smart thermostat demand response programs on Bainbridge Island and the city of Duvall. The program on Bainbridge Island was focused on peak electric load reduction; in Duvall the focus was on peak gas demand reduction. As noted above, while VPPs usually refer only to electric curtailment, we use the term broadly here to refer to DERs for either electric or gas.

In winter 2022-2023, PSE called six load-curtailment events for Duvall and seven events for Bainbridge. During events, thermostat temperatures are automatically lowered slightly, so that load is reduced. Temperatures were increased slightly before the event hours to prolong customer comfort during the event hours.

PSE sees its system peaks on winter mornings, so most events were called from 7 AM to 10 AM, with one starting at 6:30 AM. By the end of the season, 74 customers were enrolled in the smart thermostat program in Duvall, and 65 in Bainbridge. Three major thermostat brands were included in the program. Participants who enrolled in the programs, which were called 'Peak Energy Rewards,' receive a $75 annual incentive. There were no per-event incentives, nor penalties for overriding thermostat temperatures during events. Prior to events, customers received event notifications directly from the thermostat OEMs either on the device itself, or in the device's control app. For example, Nest displayed event activity on-device and in-app, Ecobee would display event information on-device, and Mysa would display event activity in-app.

Evaluation Methodology

The evaluation relied on the following three steps to obtain the most accurate estimates possible for the hourly load impact on demand response event days.

1. Data ingestion and cleaning
2. Matched comparison group selection
3. "Difference-in-difference" load impact estimation

Figure 1 gives a visual of the steps 2 and 3, the matched comparison group selection and difference-in-difference calculations. The matched comparison group selection step (shown in the first box, "Matching", of Figure 1) allows us to find nonparticipants who have similar hour-by-hour load and are from the same geographical area as the participants. This can be thought of as approximating a randomized control trial, where a subset of participants is randomly held out from the event. In both cases, customers who are not in the event provide evidence of what the event participants would have done in the absence of the program. This is particularly important in the DR context, because event days are generally more extreme than surrounding days, limiting the effectiveness of settlement-type (or day-type-matching) baselines and within subject regression approaches without a comparison group. Our matched comparison group is a pseudo–control group and helps us to calculate the baseline for the impact estimate calculations.

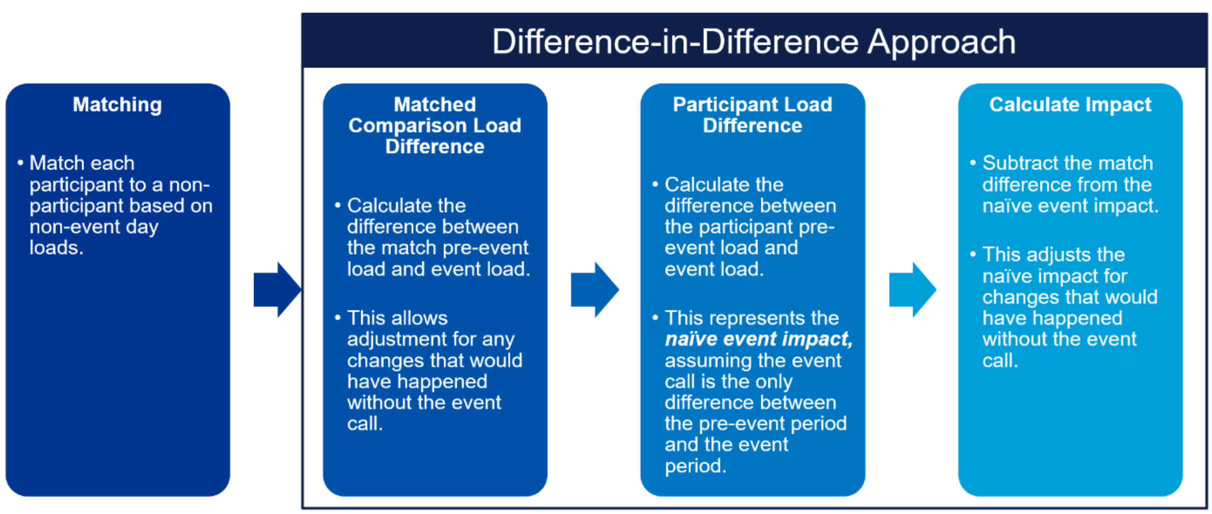

Figure 1. Impact evaluation analysis matching and difference-in-difference process

The difference-in-difference calculation (boxes 2-4 in Figure 1) allows us to correct for both (a) differences between non-event days and event days, and (b) any residual differences between program participants and the matched comparison group. The first difference is the difference for the matched comparison group between a pre-period baseline and the event day load, which adjusts for load difference between the two days. That pre-period baseline is based on the load shapes during the five days in the previous twenty non-holiday weekdays with low temperatures that were the most similar to the event day low temperature. The second difference calculates this baseline vs. event day load difference for the participant group, which is the naïve event impact, assuming the baseline and the event day load would be the same except for the event call. The difference-in-difference is a subtraction of the match group difference from the naïve event impact, thus correcting for the difference between the baseline and event day load characteristics.

Figure 2, below, shows a visualization of this process for the February 23, 2023, event for electric participants. The top frame shows the match group's baseline period consumption (blue) and event day consumption (green). The event consumption is higher than the pre-event matching consumption and is assumed to be the same as the change in consumption we would see for the participant group without an event.

The second plot shows the participant group's pre-event consumption (blue) and the actual event-day consumption (green); the difference between these two lines is the naïve event impact. The dashed black line is the participant pre-event consumption, adjusted upward by the pre-event to event difference observed in the matched comparison group in the top plot. The difference between the green line and dashed black line is the actual best-estimate demand response event impact. The shape of the observed impact is discussed below.

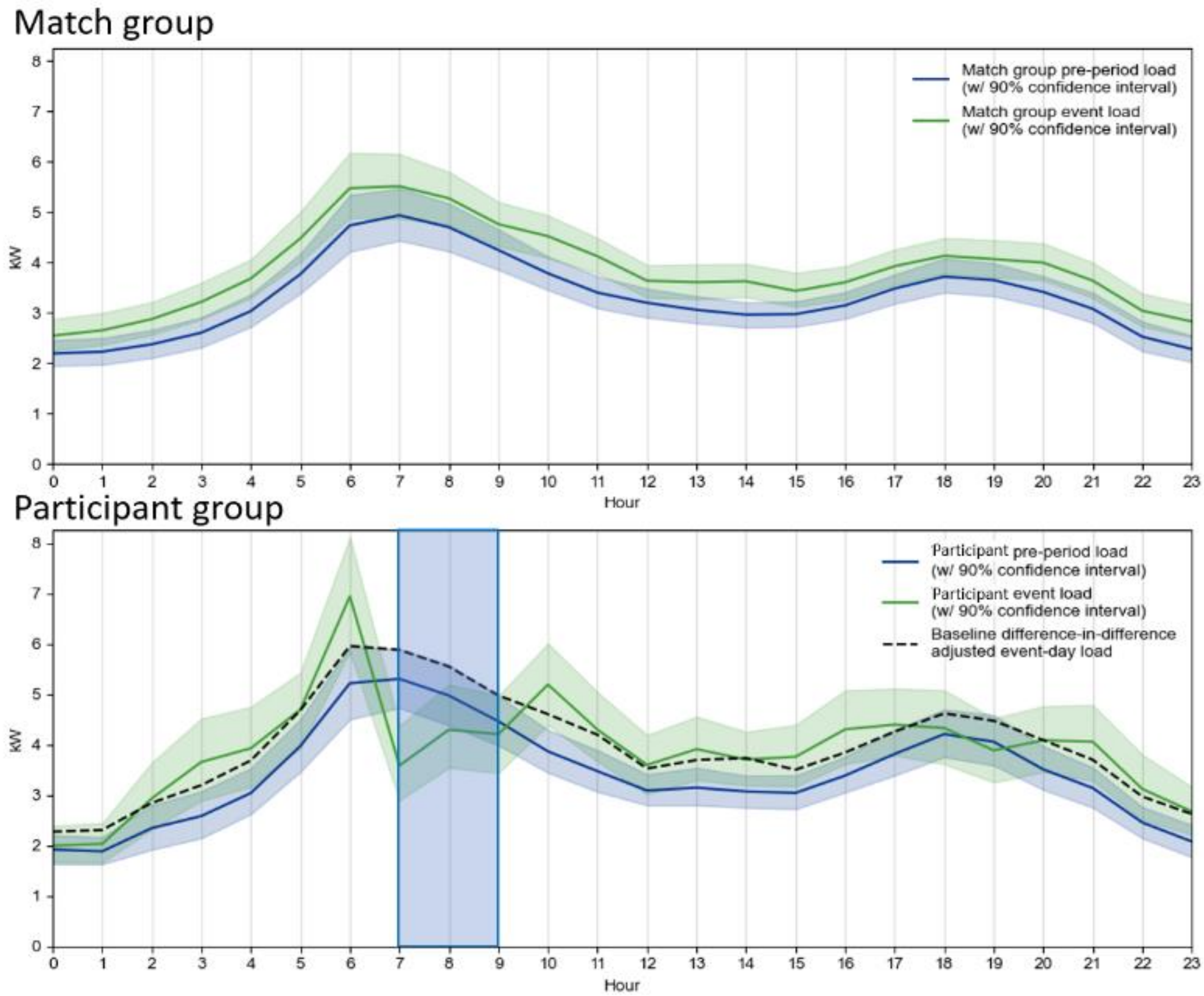

Figure 2: Visualization of difference-in-difference impact calculation for a single event day

Evaluation Impact Results

DNV estimates that the average hourly participant load curtailment achieved by the program to date is 1.59 kW for electric participants and 0.106 ccf/hr for gas participants across all event hours and all events (see Table 1). DNV also observed significant amounts of pre-heating in the single hour before an event was called, as well as significant "snapback" heating in the two hours after an event.

- Pre-heating accounted for an average load increase of 0.73 kW per customer for electric participants and 0.079 ccf/hr per customer for gas participants in the single hour before the event.
- Snapback heating accounted for an average load increase of 0.84 kW per customer for electric participants and 0.089 ccf/hr per customer for gas participants in the two hours after the event.

Table 1: Summary of curtailment, pre-heating, and snapback impacts. Average event-hour load for matched nonparticipants was 5.3 kW on the electric side, and 0.3 ccf/hr on the gas side.

Fuel Type	Impact Period	Curtailment	Units	# of Hours	# of Premises	90% CI[6]
Electric	Participant avg. curtailment across all events	1.59	kW	2 or 3	63	0.18
	Participant avg. pre-heating increase across all events	-0.73	kW	1	63	0.32
	Participant avg. snapback heating across all events	-0.84	kW	2	63	0.21
Gas	Participant avg. curtailment across all events	0.106	ccf/hr	2 or 3	68	0.009
	Participant avg. pre-heating increase across all events	-0.079	ccf/hr	1	68	0.013
	Participant avg. snapback heating across all events	-0.089	ccf/hr	2	68	0.012

DNV found that for both fuel types on average, curtailment dropped as time went on, with average impacts during each hour significantly lower than the previous hour. This trend can be seen in Figure 3 and Figure 4, which show the average per-customer load curtailment by hour into an event, averaged across all events. The x-axis in both figures shows relative hours to the start time of an event. Negative hours are the hours before an event. Hours 1-3, shown as green bars, are the event hours. The remaining positive hours are hours following an event. These data visualizations compare the nth hour of an event between events that have different start times and/or different lengths. Positive values in these plots correspond to load curtailment, while negative values correspond to increased load. It is important to note that there is increased load in the hour preceding an event (pre-heating) and increased load in the hours following an event (snapback). We see that the timing of the event relative to the system peak is particularly important, because calling an event just an hour after peak could cause increased load during that peak hour.

[6] The 90% confidence interval amount represents the amount above and below the curtailment estimates that represents the 90% confidence bounds. This means that if this program happened again with a similar group of participants, we can say with 90% confidence that the curtailment would fall between these bounds.

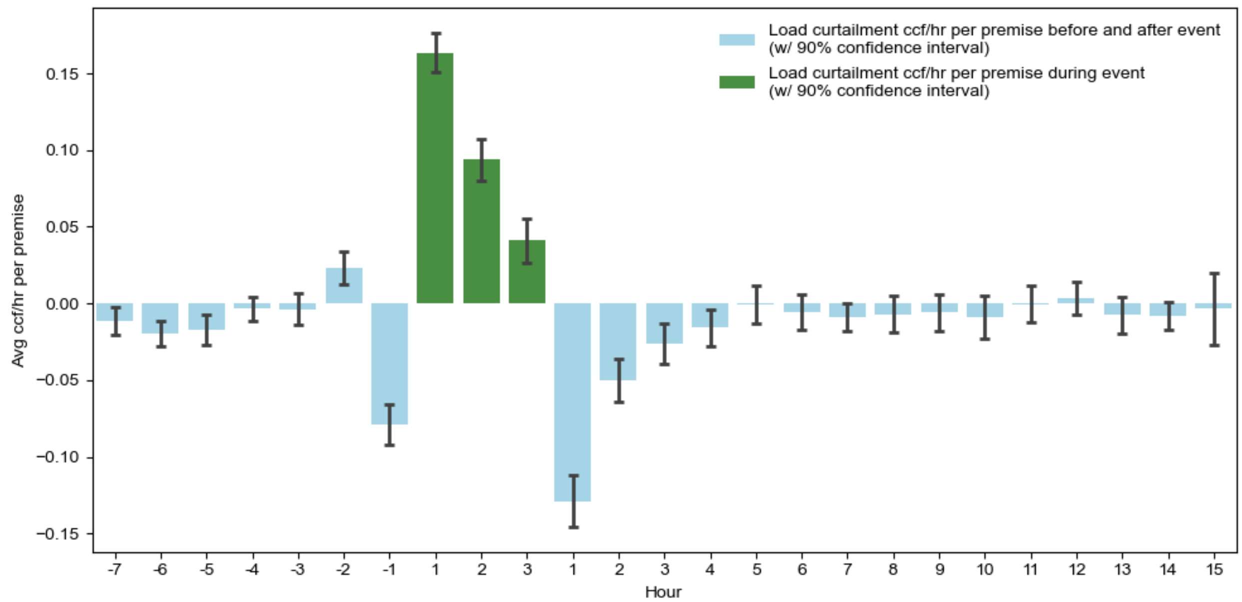

Figure 3: Load curtailment by hour into event, electric participants

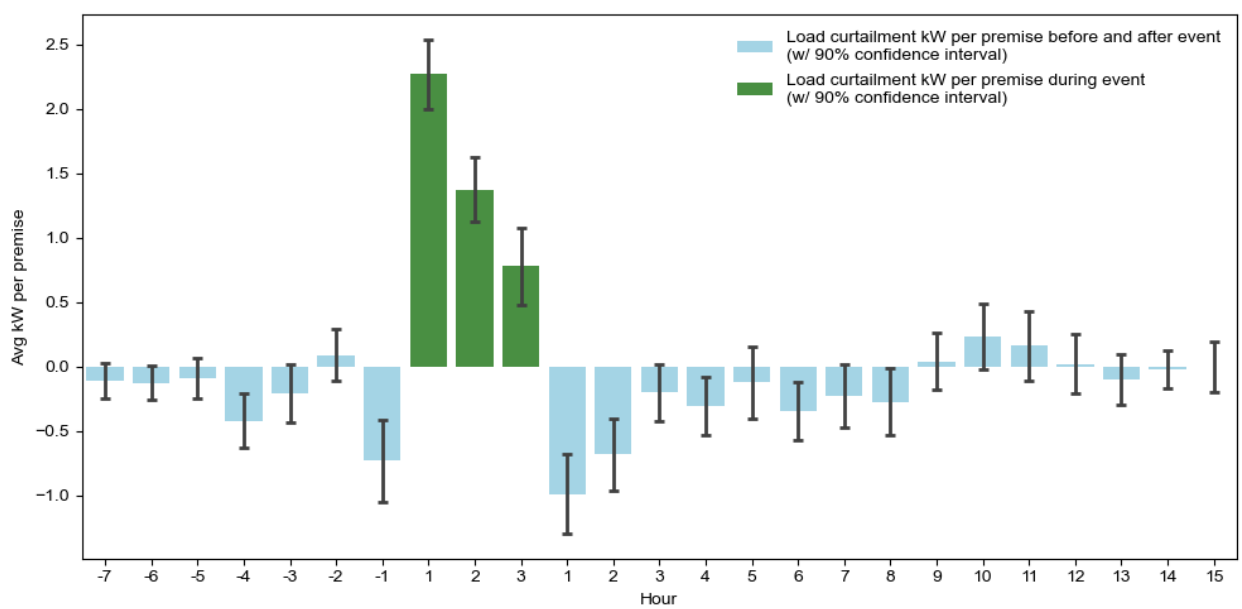

Figure 4: Load curtailment by hour into event, gas participants

Drivers of Different Impact Amounts

DNV explored whether smart thermostat device manufacturer, day of the season, or number of events a customer had experienced affected curtailment amount. The first, device manufacturer, was selected because it has previously been shown to have large effects on curtailment. The last two were chosen because it is important to know if participants will experience event fatigue, and so curtailment will be reduced over time, making it less reliable.

Our analysis revealed that curtailment differed by device manufacturer, as shown in Figure 5. For one brand, we saw no significant curtailment. For electric impacts, we also saw that, of the other two brands, one had around half the curtailment of the other. Based on this and other evaluations, we theorize this second difference (between Brands 1 and 2) could be because of confusing messaging, different thermostat control algorithms (especially regarding effectiveness of pre-heating, which appeared to be less effective for Brand 2), and different types of customers purchasing different brands.

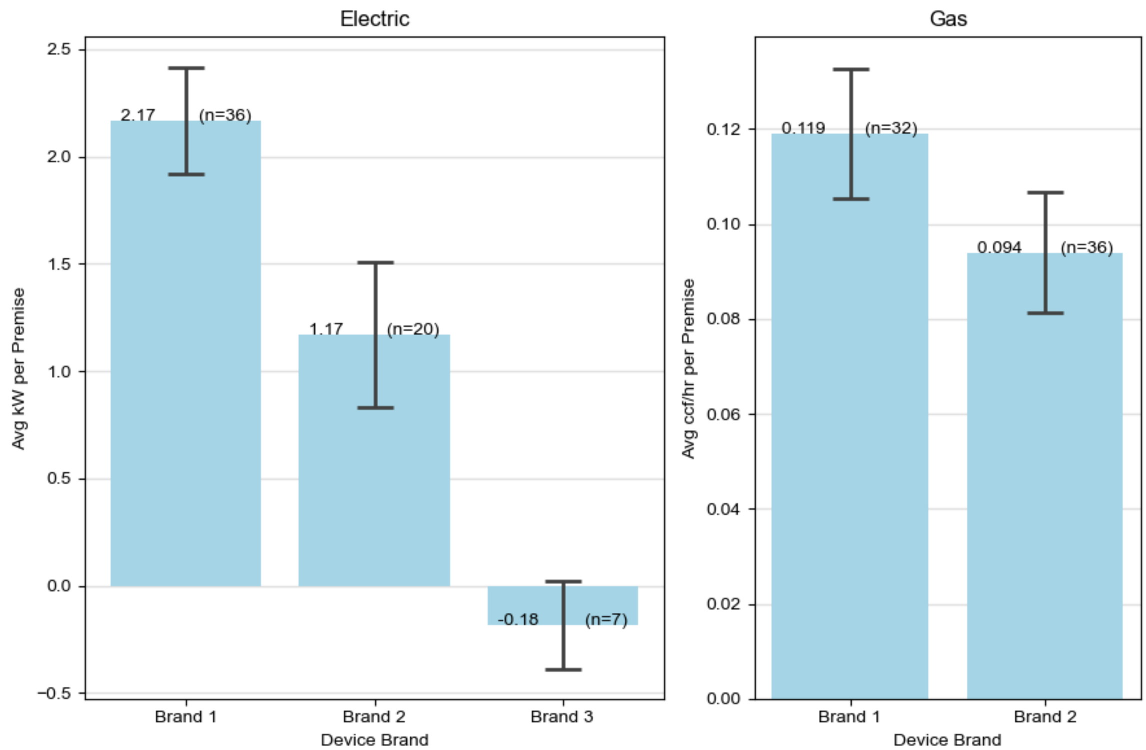

Figure 5: Curtailment estimates by device brand manufacturer

In examining whether the day of the season or the number of events a customer has experienced impacts curtailment, DNV found less obvious effects on curtailment. In Figure 6, we see that there is no clear trend in curtailment over the course of the season; much of the difference between events is likely due to temperature change and consecutive event days. In Figure 7, we again do not see a trend in curtailment based on number of events a customer has experienced, indicating that in this population, event fatigue is not leading to increased overrides. Because many customers were enrolled at the beginning of the season, there is some correlation with curtailment over the course of the season.

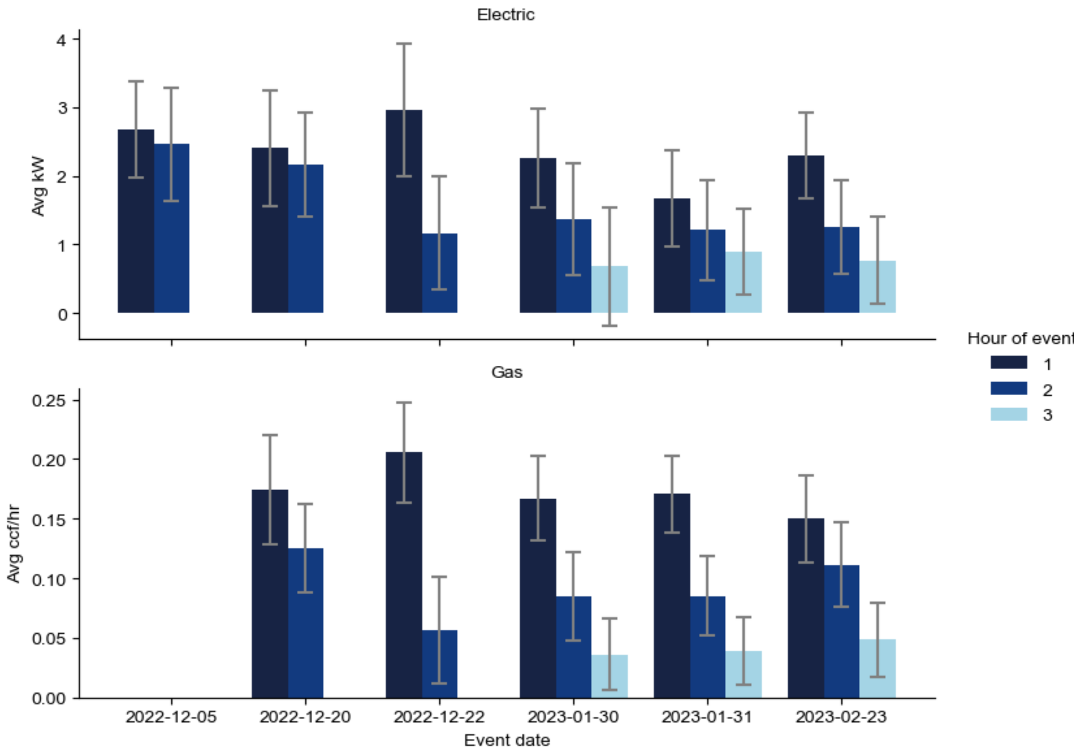

Figure 6: Average per-customer impacts by event and hour

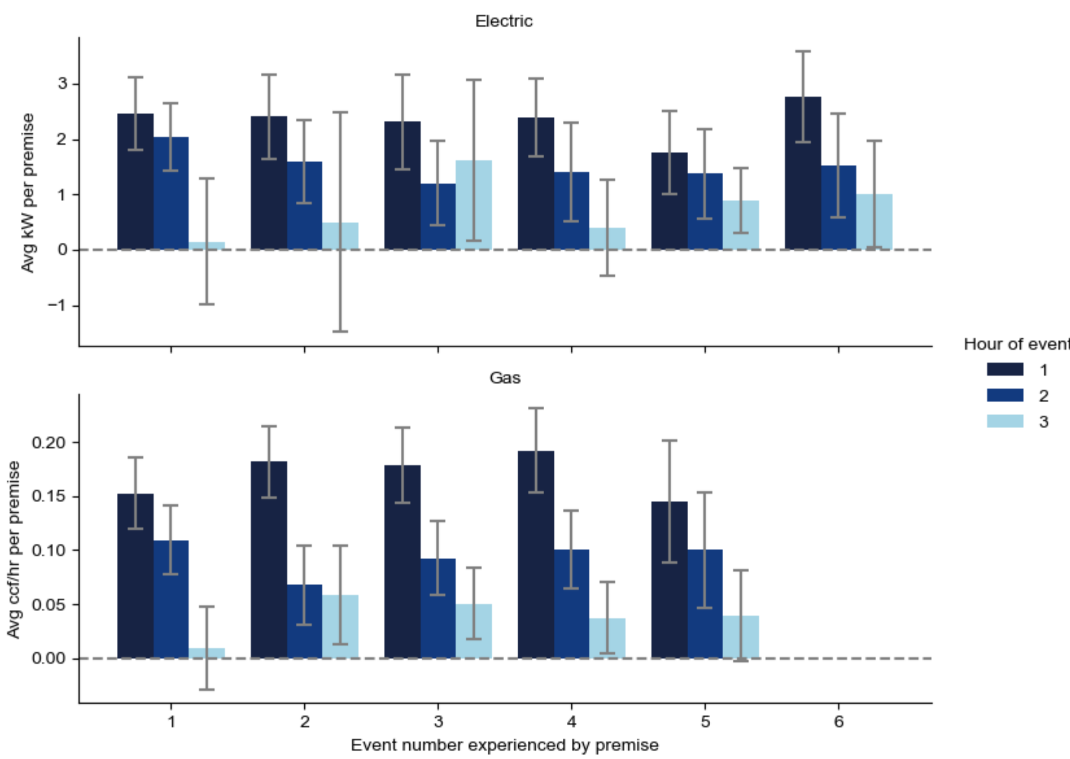

Figure 7: Curtailment by hour and event number experienced

Aggregator estimate comparison

DNV observed large discrepancies between our reported demand reduction and the program implementer's estimates, primarily because of differing baselines and partially because of different actual event-day usage in our datasets.

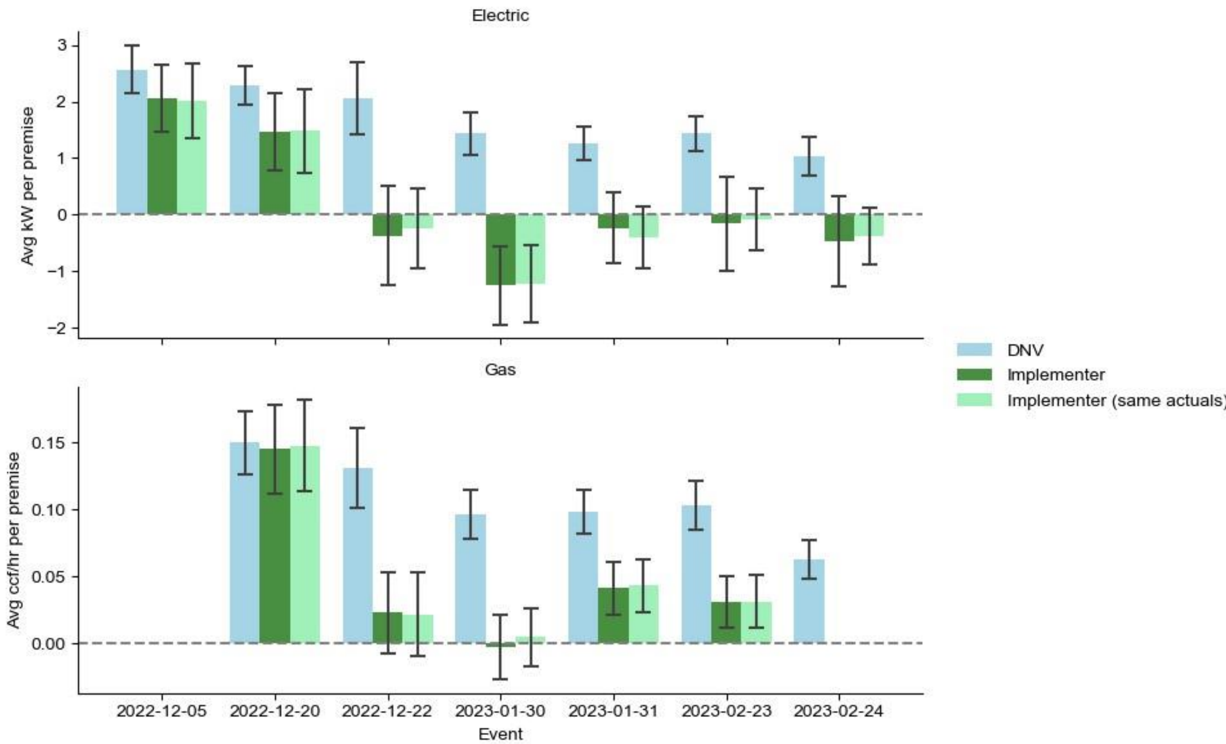

Figure 8: Comparison of DNV and implementer curtailment estimates by date

The first issue leading to these inaccurate implementer estimates is found with the data used. The implementer's customer usage data often contained values that were 2, 3, or 4 times higher than the data provided to DNV by PSE. Additionally, gas and electric data were often conflated in the implementer's data. The light green bars in Figure 8 represent the overall implementer estimate when customers with those issues were removed; we see that the estimates change very little.

Issues with the estimates likely stem largely from the implementer's use of the 10 of 10 methodology for impacts[7], which used a specific participants' usage on the 10 days before the event as the baseline. Because events are called on the coldest days, these 10 days are highly likely to have lower heating load, resulting in an underestimation of impact estimates. DNV's matched control difference-in-difference method adjusts for these cold days by looking at how the matched customer's usage varies between a pre-period and the event day. The pre-period is also selected to be more similar to the event day than the 10 days before the event.

[7] The implementer used this baseline because it is commonly used for settlement, is simple to calculate, and only requires data from participants.

Conclusions and Next Steps

In the winter of 2023, PSE made huge strides toward incorporating a VPP as part of its grid operations. It developed an award-winning VPP platform and rolled out a successful first smart thermostat DR program. Its platform demonstrated success in automated and secure customer management in the context of multiple data transfers between many entities with different types of operation (utility, program implementer, and DER equipment manufacturer). The DR program yielded significant load curtailment during event hours for both gas and electric heating customers, according to its design. The evaluation of the program gave information on how successful that program was, and which thermostat brands could continue to improve its success.

PSE's continued rollout of additional VPP components, like behavioral demand response and managed charging, in 2024 will continue to improve the magnitude of load shift achieved and fortify its VPP platform. However, it will also be even more important for PSE to have accurate estimates of event impacts soon after events, over all programs. At this point, the impact reporting provided by the implementer underestimated event impacts by about 1-2 kW or 0.5 ccf/hour, for most events. It also does not address the need for more regular and rapid evaluation to provide commission-approved filings as they relate to regulatory requirements. Being able to provide rapid, accurate evaluation results of demand response activity can empower utilities to begin program analysis at a much earlier point in the iterative perennial process of program analysis, improvement, and efforts to meet regulatory requirements. For this reason, DNV and PSE are collaborating to develop a tool that reads in customer data via an API and rapidly produces a dashboard of accurate impact estimates, using the same methodologies used in the full-scale program evaluation.

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