Evidence of Consistency over Time of the Demand Response of Large Commercial and Industrial Customers in Aggregator-Based Programs

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ABSTRACT

This paper summarizes the results of three years of impact evaluations of aggregator-based demand response (DR) programs in the state of California in the United States. The primary objective of each evaluation was to produce estimates of the hourly load changes of participating customers for each event and each program (focusing in particular on load reductions during event hours), at both an aggregate level and for certain customer types. The results of the evaluations are used as input to forecasts of expected program load impacts in future years, which are in turn used in utilities' resource planning process. Resource planners are interested in the consistency of DR load impacts over time, which is a focus of this paper.

1. Introduction

Over the past decade since the 2000-2001"electricity market crisis", the California Public Utilities Commission ("CPUC") and the major investor-owned utilities in the state have taken great strides to facilitate and promote pricing designs and programs that encourage electricity customers to reduce usage on specific days of high demand and low reserves. The three utilities, Pacific Gas and Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric ("SDG&E") have all initiated programs to install system-wide "smart" metering that allows recording of electricity use on an hourly or 15-minute basis, and communication between the utility and the meter. In addition, the utilities have all offered forms of dynamic pricing, such as critical-peak pricing ("CPP"), and various demand response ("DR") programs that provide credits to customers for load reductions below a baseline level on days on which events are called.

This paper examines one of the most successful set of DR programs, which are third-party *aggregator-based* programs. These programs are sponsored by the utilities, but operated by independent energy service/load-curtailment providers who sign up customers, nominate subsets of them for load reductions during particular months, and facilitate their responding to events called by the utilities. We conducted impact evaluations of the aggregator programs and sub-program types for three successive years (2008 through 2010) at the three utilities. The objective of the paper is to examine trends and consistencies in program participation and delivery of load impacts.

2. Nature of Aggregator-Based Programs

In aggregator-based DR programs, third-party energy service companies form "portfolios" of individual commercial and industrial customers, whose aggregated load reductions participate as a single resource for the utilities in the programs. That is, aggregators receive notices from the utility, arrange for load reductions on event days from the customers that they have enrolled, receive payments from the utilities, and allocate them to the participating customers. Aggregators can enroll and nominate customers in a mix of day-ahead ("DA") and day-of ("DO") DR program types.

Two categories of aggregator programs are available. One, the Capacity Bidding Program ("CBP"), is a *tariff-based* program offered by each of the utilities. CBP provides month-to-month capacity payments ($/kW) to aggregators based on the nominated kW load, the specific operating month and program option (DA or DO). Additional energy payments ($/kWh) are made to bundled customers based on the measured kWh reductions (relative to the program baseline) that are achieved when an event is called. The monthly capacity payments can be adjusted by the actual kWh reductions during an event, and capacity penalties apply if events are called in a month and measured load reductions fall below 50 percent of nominated amounts. If no events are called, the aggregator receives the monthly capacity payment in accordance with their nomination, but no energy payments. Participants may adjust their nomination each month, as well as their choice of available event type and event window options (*e.g.*, DA or DO events, and 1-to-4, 2-to-6, or 4-to-8 hour maximum event durations).

The other category of aggregator programs consists of *contract-based* programs, in which aggregators enter bilateral forward contracts with a utility, under negotiated aggregated DR program terms. Each contract acts as an individual DR resource and is called under the terms of the contract, either with a DA or DO trigger. The aggregator enrolls individual customers and provides a coordination arrangement by which participating customers achieve load reductions and are reimbursed by the aggregator. These programs are referred to as PG&E's Aggregator Managed Portfolio ("AMP"), SCE's Demand Response Contracts ("DRC"), and SDG&E's Demand Smart Program ("DSP").[1] For the most part, the same aggregators participate in both categories of programs. The aggregators have the ability to move customers between program categories as needed to meet their contract capacities each month.

3. Program Enrollments and Events

3.1 Program enrollments

Enrollment in 2010 in the various aggregator programs and product types ranged from 80 customer accounts in SCE's day-ahead CBP to 1,750 in SCE's day-of DRC program. With the exception of PG&E's CBP program, which includes numerous small customers in a pilot element, more customers enrolled in the DO product type than in the corresponding DA product type. This result is presumably due to larger capacity payments for load reductions under the DO option than for the DA option.

Tables 1 and 2 illustrate how enrollments in the DO versions of the CBP and contract-based program categories are distributed across industry types, by number of customer accounts and amount of load (in maximum demand) respectively. As indicated in the middle panel of Table 1, the majority of CBP-DO customer accounts are retail stores.[2] In contrast, enrollments in the day-of versions of the contract-based programs are spread more evenly across industry types. Both PG&E and SCE have nearly 600 MW of load enrolled in the DO version of the programs, while the much smaller SDG&E has nearly 100 MW.

Table 1: Aggregator Program Enrollment – *Day-Of Product Types*
(*Customer Accounts*)

	CBP			Contract-Based		
Industry Type	**PG&E**	**SCE**	**SDG&E**	**AMP**	**DRC**	**DSP**
1. Agriculture, Mining & Construction	35	2		211	51	
2. Manufacturing	25	3	12	120	174	15
3. Wholesale, Transport, other Utilities	32	2	21	113	786	21
4. Retail stores	273	364	196	129	553	24
5. Offices, Hotels, Health, Services	30	40	37	170	103	15
6. Schools	4	1	1	8	44	25
7. Entertainment, Other Services, Gov't	11		47	19	36	4
8. Other/Unknown			1	9		
Total	410	412	315	779	1747	104

[1] SDG&E operated DSP for the first time in 2010, replacing a similar CBP DO program-type that was offered by one aggregator in 2008 and 2009.
[2] The counts shown in Table 1 represent individual sites, many of which may be different branches, or outlets, of the same company, or "customer", such as supermarkets of the same brand in different cities or neighborhoods.

Table 2: Aggregator Program Enrollment – *Day-Of Product Types*
(*MW of On-Peak Demand*)

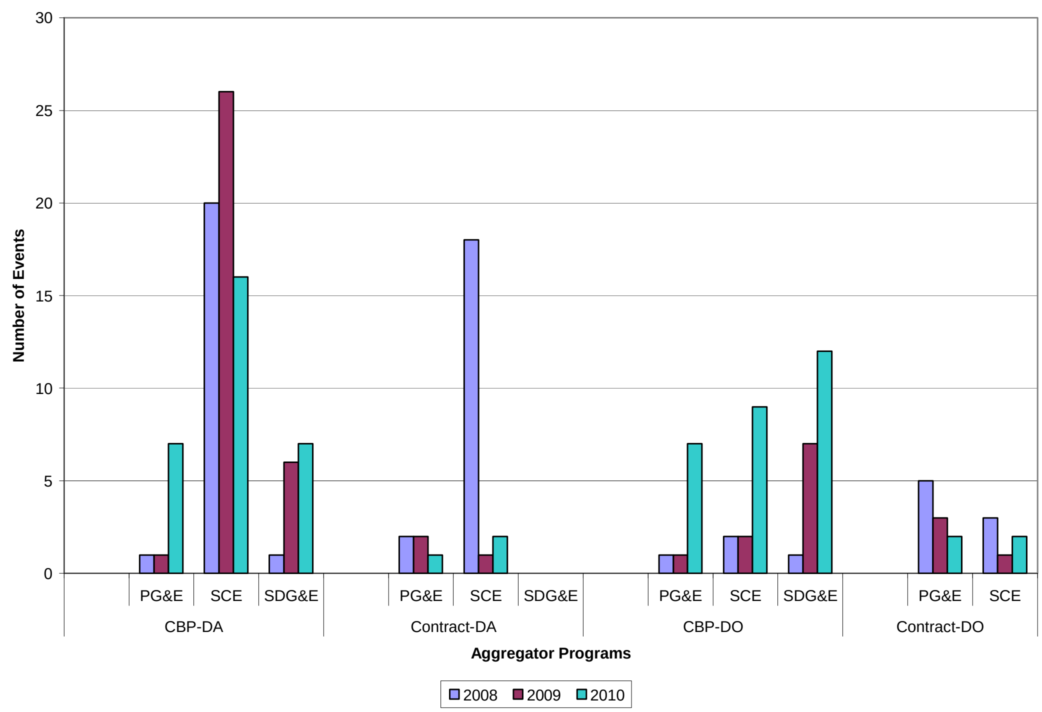
Industry Type	CBP			Contract-Based		
	PG&E	SCE	SDG&E	AMP	DRC	DSP
1. Agriculture, Mining & Construction	8.2	0.5	0.0	96.6	8.0	0.0
2. Manufacturing	29.0	0.5	3.0	94.7	112.0	2.8
3. Wholesale, Transport, other Utilities	11.1	0.6	3.6	49.0	105.9	2.5
4. Retail stores	74.4	74.1	34.8	39.6	157.5	3.8
5. Offices, Hotels, Health, Services	26.8	4.6	6.9	96.6	46.6	3.6
6. Schools	10.0	2.2	0.1	19.5	55.4	10.2
7. Entertainment, Other Services, Gov't	5.4	0.0	6.5	12.1	21.3	0.9
8. Other/Unknown	0.0	0.0	0.1	1.5	0.0	0.0
Total	164.8	82.5	55.0	409.6	506.8	23.7

Enrollments in the aggregator programs ramped up between 2008 and 2009, but remained relatively stable to 2010, partly due to reaching contractual levels of demand response capacity agreed upon between the utilities and aggregators.

3.2 Events

Figure 1 illustrates the number of events in each program category for each utility over the three years. In general, more day-ahead events were called than day-of events, and more CBP events than contract-based events were called. In a number of cases, only one or two test events have typically been called in a given year. In others, particularly SCE's CBP DA program and all of the utilities' CBP DO programs, events have been called as often as ten to 20 times in a summer.

Figure 2: Frequency of Aggregator Program Events



4. Methodology

Estimates of total program-level load impacts for each program were developed from the estimated coefficients of individual customer regression equations. These equations were estimated over the summer months for each of the three years, using hourly load data for each customer account nominated in a month containing an event.

The regression equations were based on models of hourly loads as functions of a list of variables designed to control for factors such as:

- Seasonal and hourly time patterns (*e.g.*, month, day-of-week, and hour, plus various hour/day-type interactions)
- Weather (*e.g.*, cooling degree hours)
- Event indicators—Event indicators, which were invoked when a given customer's product type was called, and were interacted with hourly indicator variables to allow estimation of hourly load impacts for each event.

The resulting equations provide the capability of estimating hourly load impacts on every event day. In addition, the customer-specific equations provide the capability to summarize load impacts by industry type and location, by adding across customers in any given category. Finally, uncertainty-adjusted load impacts are calculated to illustrate the degree of uncertainty that exists around the estimated load impacts.

5. Estimated Load Impacts

5.1 Nature and consistency of estimated load impacts

As noted above, load impacts are estimated for each hour of each event. Such estimates are illustrated in Figures 2 and 3 for PG&E's AMP DO program and SCE's DRC DO program for two-hour events called in 2010. Load impacts are approximately 100 MW for both programs, the largest of all of the program types. Note the difference in the shapes of the reference loads (i.e., the load profile that we estimate would have occurred if the event had not been called) for the two programs, which reflect differences in industry mix, such as more office building enrollment in PG&E's AMP.

Figure 2: Hourly Loads and Load Impacts – *Typical PG&E AMP DO Event*

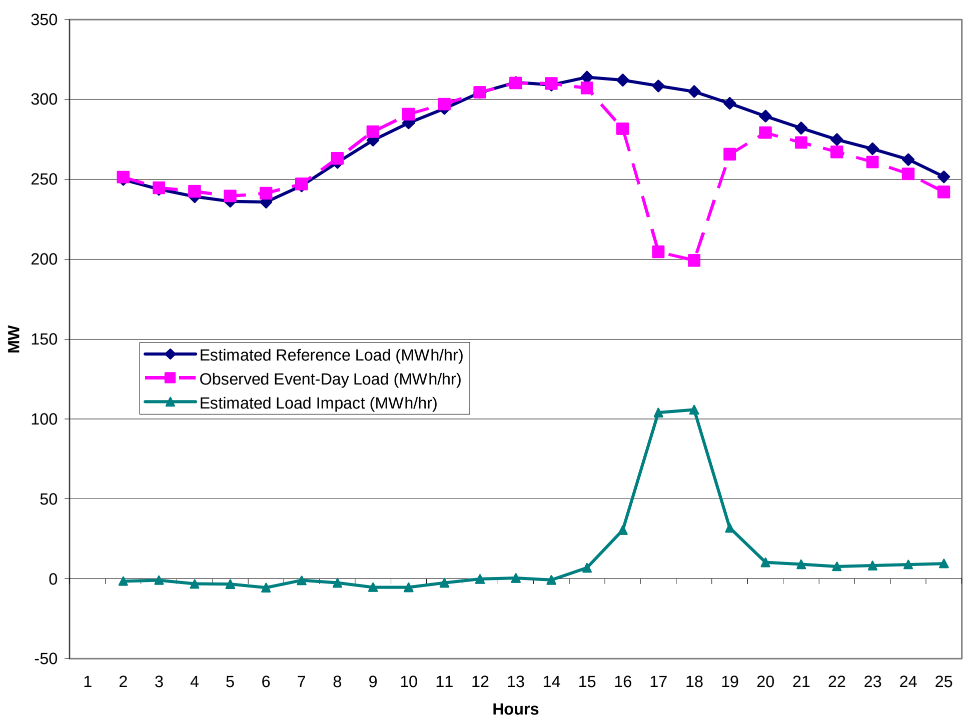
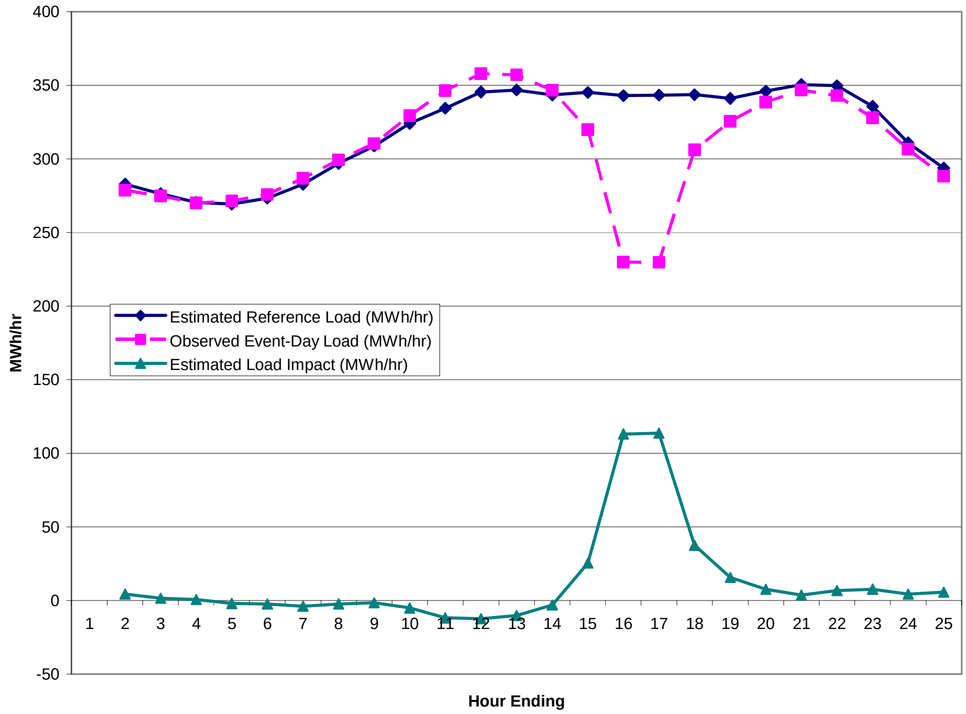


Figure 3: Hourly Loads and Load Impacts – *Typical SCE DRC DO Event*



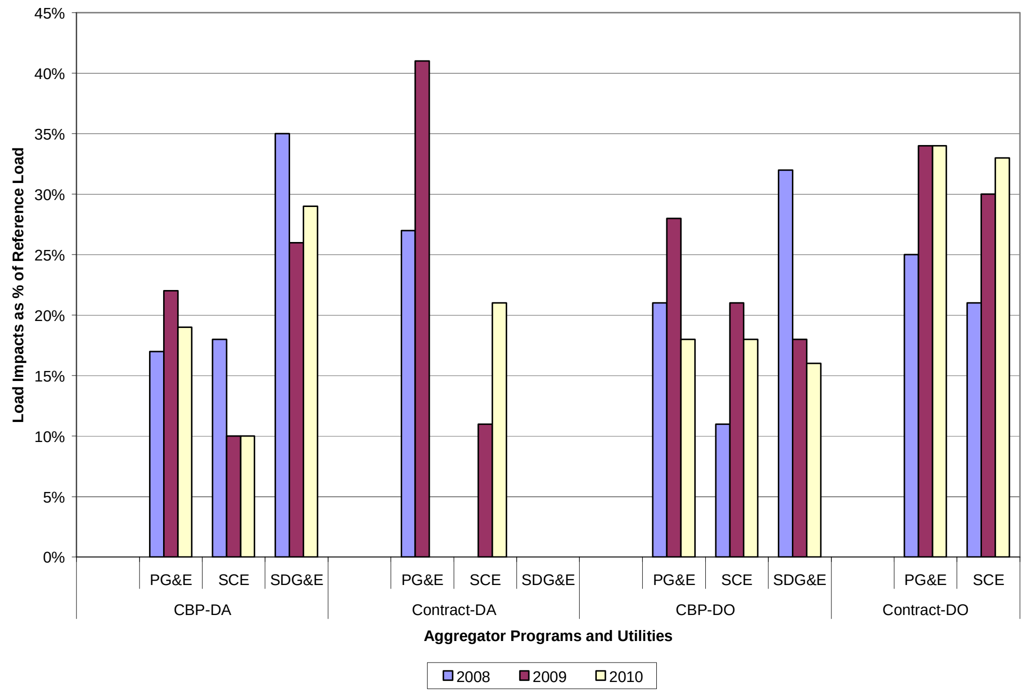
For purposes of comparing estimated load impacts across programs and years, we summarize the hourly estimates by the *average hourly* load impact for the average or typical event, and then convert those values to *percentage load impacts* measured relative to the estimated reference loads.[3] Figure 4 summarizes values of these average hourly percentage load impacts over the three years. Several observations can be made about these values. First, the percentage load impacts are relatively consistent across years for a given utility and program type.

Second, the values are relatively high, ranging from about 10 percent to 40 percent across program types and utilities, with most values in the 15 to 35 percent range. These percentage load impacts are large relative to many previous findings for dynamic pricing (e.g., CPP) programs for residential customers in particular, but also for non-residential CPP rates in California. For example, percentage reductions in on-peak demand in CPP pilots for residential customers with no enabling technology have typically ranged from 10 to 20 percent, while only customers with enabling technology have achieved reductions ranging from 25 to as much as 50 percent. For voluntary non-residential CPP in California, percentage load impacts in two cases ranged from three to six percent, while in another case with much higher critical prices, the percentage was 19 percent. It is possible that these relatively low values are partially a result of the existence of the aggregator programs. That is, the hundreds of large commercial and industrial customers participating in the aggregator-based programs may be among the most price-responsive customers, and they are not eligible to enroll in CPP.

Third, the load impact values for the aggregator-based programs depend on several key factors, including the mix of industry types enrolled and nominated each month, the incentive payments provided (e.g., higher for DO program types than for DA types), and the weather conditions on the day of the event. It is also likely that the relatively large load impacts are due in part to technical assistance and incentives provided to customers by the aggregators.

[3] For some programs, events may differ in terms of which aggregators are called to provide load reductions. This is particularly the case for test events or re-tests. To provide the most comparable values, we generally average only over those events in which all aggregators were called, thus representing a typical event.

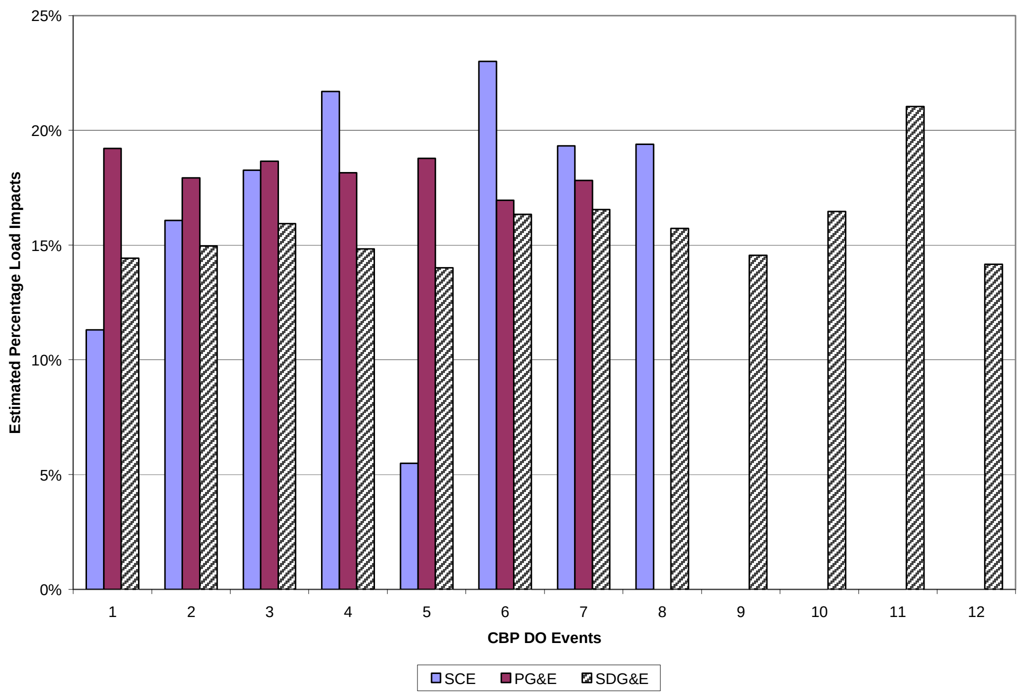
Figure 4: Percentage Load Impacts by Program and Year



Another notion of consistency in the aggregator load impacts is that of consistency across events in a given year, though this measure is only relevant for program types for which a number of events were called. Figure 5 shows estimated percentage load impacts for each of the CBP-DO events called by each of the utilities in 2010.[4] As is evident, with only a couple of exceptions, the percentage load impacts are quite consistent across events, at around 15 to 20 percent..

[4] For clarity of presentation, the events are shown in sequence for each utility and do not necessarily occur on the same date as the indicated event number for another utility. That is, event 2 may have occurred on July 15 for one utility and July 22 for another.

Figure 5: CBP-DO Percentage Load Impacts by Utility and Event

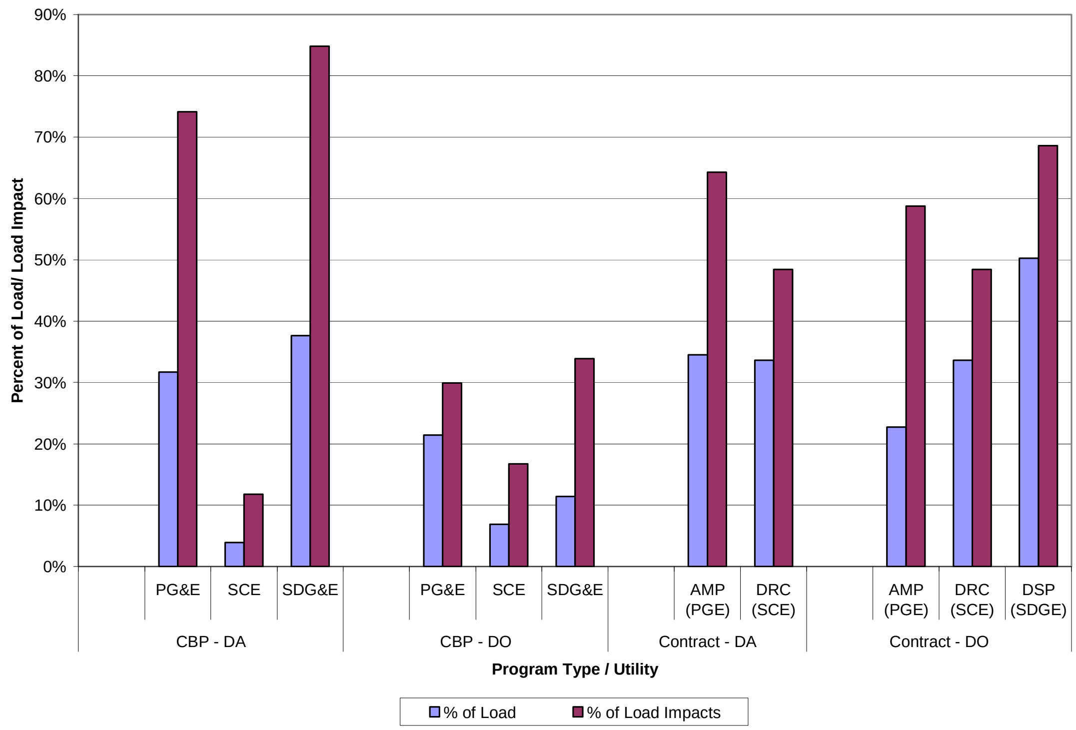


5.2 Concentration of estimated load impacts

Even given the relatively large magnitude of percentage load impacts discussed above, it is interesting to explore the concentration of load impacts across all participating customers for a given aggregator-based program and type. Figure 6 illustrates this concentration for 2010. The figure shows the percentages of *load* and *load impacts* that are accounted for by the top five percent of customer accounts, measured by the largest average load impacts across events. In seven of the eleven IOU program/product-types, approximately half or more of the total program load impacts are accounted for by these top five percent of customers.

Note also that the percentage of total load of the top five percent is greater than five percent (with one exception), but always less than the percentage of load impacts. This implies that while some of the concentration of load impacts is due to these top customers being larger than average, they are also relatively more responsive than the average customer in the program/product type.

Figure 6: Concentration of Load Impacts – Percent of Load and Load Impacts Accounted for by Top Five Percent of Customer Accounts (2010)



6. Conclusions

The aggregator-based demand response programs at the three major investor-owned utilities in California appear to provide an effective alternative to dynamic pricing for large commercial and industrial customers as a mechanism for achieving load reductions during events called to reflect high system loads and tight reserves. Over the 2008 to 2010 period they achieved and maintained enrollment of approximately 5,000 large customers, accounting for some 1,300 MW of maximum demand. Estimated load impacts across utilities and program types (including day-ahead and day-of notice) are generally quite consistent across events in a given year, and across years for particular programs. The load impacts are also quite large in percentage terms, typically ranging from approximately 15 to 35 percent of the peak load that would otherwise have occurred had events not been called.

References

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