Demand Response: It's a Resource, So Treat It Like One!

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ABSTRACT

With new and existing demand response (DR) programs being slated for monumental growth in the next five to ten years many unexpected issues are arising. Some of the most important have to do with the impacts and how they are counted. Are the impacts considered a resource? Or are they simply a load decrement? The presentation explores the issue in three general areas, program design, resource planning, and cost of service. Through in-depth interviews with 10 utilities[1] across the US we learned about current utility thoughts and practices when considering DR impacts. We also explored future scenarios and possibilities to discover what utilities might need to change going forward. We found that one of the most challenging areas when considering DR impacts is cost allocation. Most utilities do not currently account for DR load impacts in their cost-of-service studies, but it is an area of growing concern. While the process of allocating costs is not directly linked to program impacts, DR events called on the highest load days, which usually includes the system peak day, can affect future cost allocation and rates in inappropriate ways. It even could end up double counting the benefits for some programs. We used publicly available data from Pacific Gas & Electric (PG&E) to explore the effect on cost-of-service allocators of calling events on both the system peak day and several of the highest load days to illustrate the effect of these issues, and discovered some interesting and unpredictable results.

Introduction

This report focuses on demand response as a resource and the appropriate treatment of DR impacts. We believe that DR is not only a viable resource, but a critical resource for the electric utility industry and, therefore, it should be treated consistently as such. Not doing so will cheapen the value of DR, create inappropriate price signals, and keep the industry from realizing the efficiency of balancing supply and demand. The primary focus of the report and the driver of this research is how DR events are treated in cost-of-service allocation, but we include two other areas of consideration, program design and load forecasting/resource planning, for context and background. We talked with 10 utilities across the country to uncover their experiences and thoughts on the counting of DR impacts. We also used actual data to explore, through in-depth examples, the consequences to cost-of-service allocations of counting DR impacts in different ways.

Program Design

For the purpose of this report, we define program design as all the work that goes into preparing a program before it is offered to the public in full roll-out, including fine-tuning the

[1] Utilities contacted were BC Hydro, Idaho Power, NV Energy, Oklahoma Gas & Electric, Pacific Gas & Electric, Public Service Company of New Mexico, Puget Sound Energy, San Diego Gas & Electric, Southern California Edison, and Xcel Energy.

options. There are many aspects of program design, such as defining program parameters, designing rates and incentives, piloting and testing, and of course, measuring the cost effectiveness of the program. How DR impacts are counted plays a role in the program design process in two areas similarly, during the cost-effectiveness screen and when setting rates and incentives for customers. In this paper we describe the role in cost-effectiveness. The role is similar in setting rates and incentives.

Cost-Benefit Testing and Utility Practices

For most DR programs the approval process, whether internal or regulatory, involves a cost-benefit analysis screening. With the exception of experimental pilot programs, only those programs that pass the test are considered cost effective and allowed to be implemented. The most difficult part of cost-benefit testing involves identifying all the costs and benefits associated with a particular program. There are several widely accepted cost benefit tests described below. The descriptions of these tests are based on the EPRI Energy Efficiency Planning Guidebook and each of the five tests has a different perspective.

- The participant test examines the program from the participant's perspective, asking whether or not participants are better off as result of the program.
- The total resource cost test (TRC) examines the program from the perspective of both the utility and the ratepayer, asking whether or not total resource costs decrease.
- The ratepayer impact test (RIM) examines the program's effect on rates, asking whether rates will increase as a result of the program.
- The utility cost test addresses the utility's total cost, asking whether revenue requirements will decrease.
- The societal test addresses society as a whole, asking whether the cost to society will decrease as a result of the program.

In four out of the five tests, utility avoided costs make up the bulk of the benefits. The avoided energy, capacity, distribution, and transmission costs are determined by the estimated impacts of the DR program.

Every one of the ten utilities we spoke with said that some or all of their DR programs undergo a cost-benefit analysis, and for those that do, the avoided capacity resulting from DR program impacts are counted as benefits in the cost screening process. So for the most part, from a design perspective, DR program impacts are considered a resource in utility DR planning practice. Two utilities have some DR programs which do not undergo a cost benefit screening. The reason cited by both utilities was that the costs for those programs (both were pricing based programs) are recovered through the regulatory process. One utility manager stated that pricing programs simply do not have any proven capacity value and therefore they are allowed to recover program and incentive costs through rates. Pilot programs are another example of programs that may not undergo a cost screening. Pilot programs are used to assess the impacts and customer response to a program and the cost effectiveness of the pilot itself is usually not considered.

From a program design perspective, it is important to count the future estimated impacts of a DR program as a resource because that is the primary benefit of the program – the avoided capacity justifies the program. During the design phase, each program will undergo some type of cost-benefit analysis to determine if the program should be implemented. The avoided capacity costs associated with the reduction in load are usually the program's principal benefit, and often the only benefit. Note that this is where the program gets credit. Program incentives and rates are also often based on avoided capacity costs.

Resource Planning

In this section we will look at different types of DR programs and how utilities treat them with respect to resource planning. First, we define the different types of programs and look at how those types might be treated. Then we take a brief look at what some utilities are actually doing with respect to DR programs and resource planning.

Forecasters and resource planners often look at DR impacts in different ways. For a forecaster, it is important to include the impacts of all DR programs in the load forecast. This will allow the forecaster to accurately forecast load with and without DR programs and to differentiate impacts from new and existing programs. Resource planners look at the picture differently. For many utilities, at least some of their DR program impacts are included as a resource in formal resource planning. A utility will usually decide what programs are considered a resource based on the type of program. We found that utilities tend to categorize their DR programs into three categories.

- *Dispatchable programs:* These include curtailable, interruptible, and direct load control (DLC) programs. These are the programs that the system operators see as certain to provide load reduction. They might have control over the actual end-uses, as in a DLC program, the program may have a proven history of load reduction, or customers may face heavy penalties for non-compliance, as in an interruptible program.
- *Event-based pricing programs:* These include critical peak pricing (CPP), variable peak pricing (VPP) and peak time rebate (PTR) programs. These programs might still be considered dispatchable, because they can be called on relatively short notice when needed, but customers are not under utility control, and face mild consequences, if any, for failing to reduce load.
- *Non-event based programs*: These mainly refer to time-of-use (TOU) rates. While TOU rates definitely provide peak load relief, the relief is always there and built into the load shape for all days. It does not make sense to consider these programs as a resource in the same sense as the event based and dispatchable programs, since they cannot be called for a particular day.

Generally, dispatchable programs, especially curtailable and interruptible programs, are considered a resource, and are treated just like generation by system operators. The key here is that the system operator is confident that the load reduction is reliable. Event-based pricing programs differ from traditional dispatchable programs because their impacts are more variable. This variability, if not properly understood, can impact a system operator's ability to treat the program like generation. Still, utilities can and do consider event-based pricing programs a resource assuming that they have a proven reliability and size.

Utility Practices

What are utilities actually doing? Two of the utilities we spoke with, Southern California Edison (SCE) and Oklahoma Gas & Electric (OG&E), currently include some programs in their resource planning process, and that decision is based on program type. They define dispatchable programs as a resource and exclude pricing programs. Interestingly, both SCE and OG&E are either piloting or in the process of rolling out large scale pricing programs. SCE is rolling out universal PTR and currently has a mandatory CPP rate for C&I customers with peak demand over 200 kW. OG&E is planning a residential dynamic pricing pilot. When talking with these utilities about what they might do in the future with these large scale event-based pricing programs in full deployment, both were a bit uncertain. OG&E has historically viewed pricing programs as being devoid of capacity value. However, the possibility of a large and reliable (reliable being key) dynamic pricing program at OG&E seems to have sparked a reconsideration of current practices. SCE had a similar view, that after allowing some time for the program to become established, it would be included in the resource planning process.

NV Energy also currently includes certain DR programs in the resource planning process. They base their decision on whether or not to include a program on the size and reliability of the program rather than the program type. Their residential AC cycling program, Cool Share, reached a total of over 50 MW of load reduction in the summer of 2008 and is now operated as a resource by their system operators. This program also has the ability to target smaller geographic areas to aid in system reliability at the feeder level. In this case, while the program still falls into the dispatchable category, it is the fact that the program is proven that allows it to be run like generation.

We are seeing similar changes in markets throughout the industry with DR now being bid into day-of and day-ahead markets on a more equal footing with generation, both in the CA-ISO and PJM. In addition, fast DR, or DR as ancillary services, is also being tested in both markets, which will allow DR programs with a very fast response time (less than 10 minutes) to function as ancillary services at the ISO level.

Cost of Service

Cost of service may not be the first thing that jumps to mind when thinking about the impacts of DR programs. As programs grow in size, it will be important to think about how DR events affect cost-of-service (COS) allocation. Many utilities use some type of Coincident Peak (CP) method to allocate costs, which means that a customer class's share of costs is based on that class's contribution to system peak. So a DR program called on the system peak day could lower a class's contribution to peak, making that class's share of costs lower. This is a problem on two levels. First, it can inappropriately and unfairly change (lower or raise) the allocation of costs to different rate classes, and second, if DR programs are truly a resource, then the decision to call on a DR program instead of an alternative resource (a peaking generator or purchasing power) should not affect the allocation of costs for future rates.

To clarify, we are not talking about the allocation of DR costs – we are describing how DR events on system peak and other high load days can affect the allocation of all costs (primarily fixed costs) in a cost-of-service study. Consider two scenarios. In the first, on the system peak day, the system operator does not call an event, but calls on a peaking generator to meet the system load for just a few hours in the hottest part of the day. The system load is measured, and class loads are estimated using load research samples. In the second scenario, a DR event is called to cover those same few hottest hours. In this case, the system load is reduced from what it would have been in the first scenario, as is the total net generation. The DR load takes the place of the additional peaking generation. From an operational standpoint, the only difference between these two scenarios is which resource the system operator chose to use. However, the implications of that choice can be far reaching, if the load reduction is not accounted for appropriately.

First, we will address current utility practices, and then we will then explore the possible consequences of not accounting for DR impacts in cost allocation and provide some detailed examples.

Utility Practices

We found that nearly all the utilities we spoke with agree that in principle, DR impacts should be added back in to loads if a DR event is called on the peak day. However, only one out of the ten actually does this for any program. There are a variety of reasons why, the most important being that in the past, this has not been an issue. DR programs at many utilities are still fairly small. Many programs are just beginning or have low participation, so that even if an event was called on the peak day, the impact is so small its effect is inconsequential in the cost-of-service allocations. Another reason is that many utilities have programs that are either underutilized or are only for system emergencies. In these cases, programs are rarely if ever called and almost never coincide with a system peak day. PG&E and SCE both had similar stories about their Base Interruptible Programs (BIP). It seems that most utilities are not facing situations where DR programs are called on system peak days, and if they are, the load reduction is too small to make any difference. OG&E is the only utility we spoke with who is adding DR impacts back into system and class loads for cost of service.

OG&E currently only has DR programs for large C&I customers fully deployed, although they are beginning a pilot program that includes pricing-based DR for residential and small commercial customers. For their C&I programs the impacts are consistently treated as a resource. They have been following the practice of adding impacts back in to the system load for cost of service for the last 5 or 10 years. They use the estimated avoided MW impact from their measurement and evaluation group and add that load back into the class load on an hourly basis. As for how future pricing programs impacts will be treated, it is too early to tell. While the current OG&E policy is to view pricing programs as having no capacity value, the company would add impacts back in for any pricing program that is large enough and reliable enough to be called by system operators as a resource.

NV Energy's Cool Share AC cycling program is truly operated as a resource. With an average of 33 events per year, they definitely have a high probability of hitting the system peak day. Even so, in the past they have not adjusted class and system peak loads when events fall on the system peak days. However, NV Energy reported that they have identified this as an issue, and he is involved in discussions with the rates organization about adjusting loads in the future.

Nearly all of the utilities admitted that regardless of what they are doing now, this is an issue that they will likely need to consider in the future. This is especially important for utilities with large scale DR deployments looming in the coming years. The industry is trending back toward DR as a resource and while to our knowledge, the effect of DR programs on cost of service has not yet been formally addressed, we feel that it is an important aspect of DR policy and that DR impacts should be treated consistently.

What Are the Consequences?

Beyond the philosophical issues surrounding treating DR programs consistently, what are the practical implications of not adjusting loads by adding DR impacts back in for cost allocation? The effect will depend on the cost allocation method used, but in most cases, the effects across different allocation methods will be similar. There are several possibilities.

The lower load for a class with DR program participants might help that class in the cost allocation process by decreasing the amount of cost allocated to that class at the expense of other classes. If rates for a class that responds to the event are lower because they are allocated fewer fixed costs, then the utility is rewarding those participating customers twice for the DR reduction. They get a benefit once when they are compensated for participating in the program and a second benefit in the form of these slightly lower future rates. Additionally, there may be a sort of free rider benefit for non-participating customers that are part of a class which includes both participants and non-participants. If that class does get allocated fewer fixed costs, then all members of the class benefit from lower rates, whether they participate in the DR program or not.

Shifting the system peak hour to another day or time through the use of DR could either help or hurt the responding class. If the time of the system peak moves the results are unpredictable. Shifting the system peak hour to another day or time could also help or hurt other classes that are not part of DR programs. For example if the system peak moves to an earlier time as a result of an event, commercial classes may be hurt by having a larger percentage of load at that time. This would be the case if the peak moved from, say 4:00 pm to 2:00 pm. Shifting the system peak to a later time, say 6:00 pm would have a similar negative effect on the residential class. We learned that the more we thought about this situation, and the more people we asked about the possible consequences, the more complicated things got. It seemed the possibilities were endless, so what we needed was a real world example.

Because there are not many utilities operating DR programs of the size and quantity to make a difference in cost allocation, we decided to use real load data, but projected future DR load impacts in our example. All the data that we used in this example is publicly available. The system load data was built up using Pacific Gas and Electric's 2008 dynamic and static load profile data. We included profiles for residential, small general service, medium and large general service, and agricultural classes. We did not include standby, master metered accounts, or lighting customers. The profiles were aggregated to rate class levels available in PG&E's 2008 Form 1 FERC filing, and then multiplied by the Form 1 numbers to gross up to a system load. The class and system load shapes will not perfectly reflect PG&E's actual load and allocations, since not all customers are accounted for, line losses have not been included, etc., but they do give a very reasonable estimate of class and system load shapes for our purely illustrative purposes. Using this method, we accounted for 98.5% of the total population and 99.7% of the system peak.

Figure 1 is a stacked area graph of the system load on the peak day. The shape is typical of most utilities with medium and large commercial and industrial class making up the largest portion of the load and a late afternoon peak driven by the blend of increasing residential and still high commercial and industrial loads. The peak hour here is at 3 pm PST (which is actually 4 pm PDT). Table 1 illustrates the class contributions to peak on the peak day. We added a column that assumes a fixed cost of $50 million to be allocated to each class using a single coincident peak (1CP) allocator. These numbers are purely for illustrative purposes to give some sense of how cost allocations might change as DR impacts are included.

Figure 1 PG&E System Load: Peak day - July 8, 2008, 4:00 pm

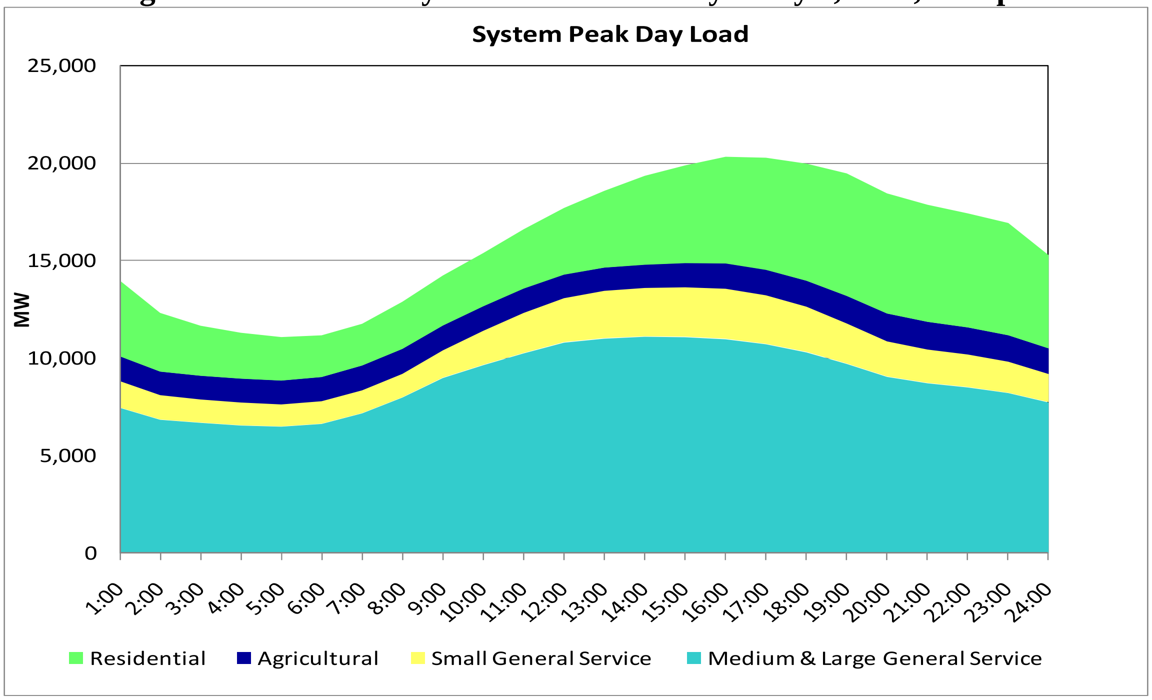


Table 1 Class Contribution to System Peak

7/08/2008 4:00 pm DST			
Class	**MW**	**% Contribution**	**Fixed Costs ($)**
Agricultural	1,303	6.4%	3,203,933
Medium & Large General Service	10,987	54.0%	27,011,221
Residential	5,469	26.9%	13,444,386
Small General Service	2,579	12.7%	6,340,460
Total Load	20,338		$50,000,000

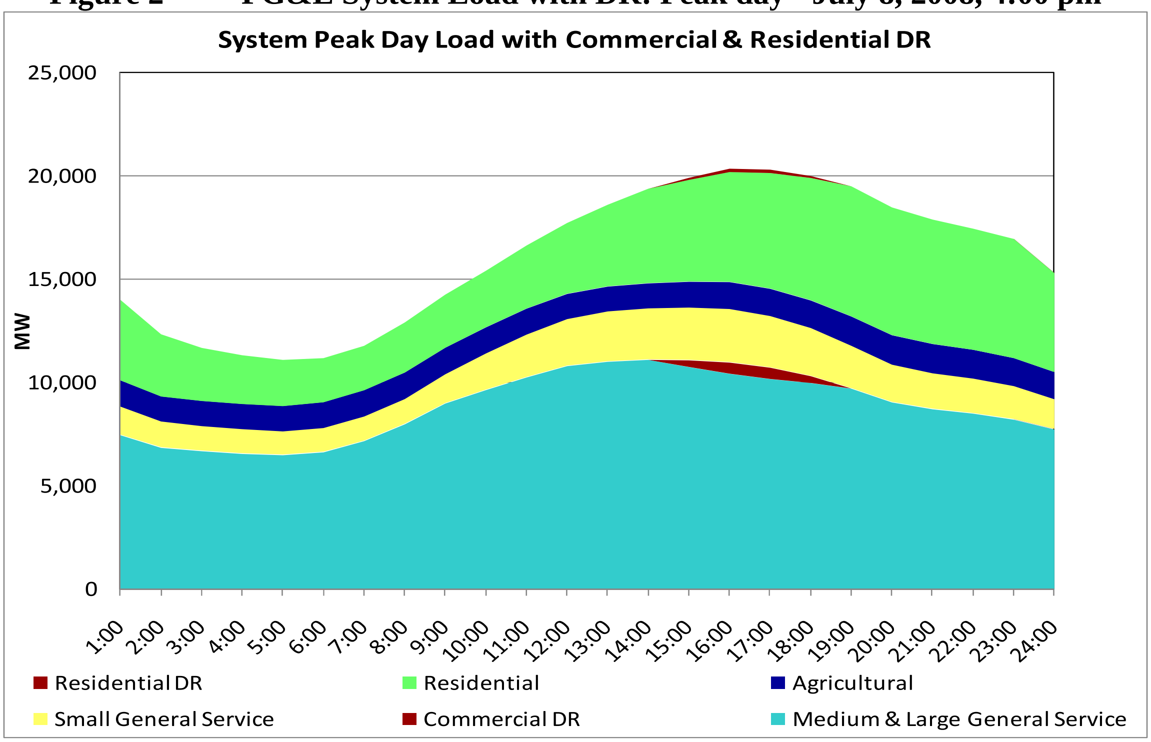
The next task is to apply some DR program impacts to this data and see what happens to the system peak and cost allocations assuming a simple 1CP cost allocation method. For each scenario, we will compare what would happen if DR events were called, but the system and class loads were not adjusted to add the load reduction back in. For the impacts, we used estimates from PG&E's report "Overview of Expected Demand reduction Capacity of 2009-2020 Demand Response Portfolio." The report contains monthly estimates of PG&E DR program impacts both for a 1 in 2 weather year and a 1 in 10 weather year. The load reduction estimates represent the average impact over the event period (2-6 pm) on the monthly peak day assuming that the entire DR portfolio is called. Our examples incorporate impacts from 2012 for a 1 in 2 weather year. We chose to use 2012 because it represents impacts associated with a fully deployed set of DR programs rather than programs that are still ramping up. We chose to aggregate the different program impacts into two categories, Residential DR program impacts and Medium and Large General Service Program impacts. Table 2 presents the impacts by program and category from the PG&E Report. The Peak Choice program replaces PG&E's Base Interruptible Program (BIP), Peak Day Pricing is PG&E's general service CPP-style rate, and the Smart Rate is the residential version. The Smart AC program is a residential AC cycling program.

Table 2 2012 Estimated DR Program Impacts (July)

Program	Eligible Customers	July 2012 MW
Peak Choice - Day of	Medium & Large GS	225
Peak Choice - Day Ahead	Medium & Large GS	2
Peak Day Pricing	All - Non Residential	208
Medium & Large General Service DR: Total		**435**
Smart AC	Residential	64
Smart Rate	Residential	67
Residential DR: Total		**131**
Total DR Reduction		***566***

Figure 2 below presents the system peak day graph using the same data as Figure 1, but with the DR reduction for each class highlighted in red. The total load represented by the top line remains the same as in Figure 1 above.

Figure 2 PG&E System Load with DR: Peak day - July 8, 2008, 4:00 pm



So what happens to the system peak and to cost allocations when we incorporate the DR reductions from Table 2? The first thing that we found was that calling an event for just one or for both of the classes resulted in the same change to the system peak time. PG&E has a small enough variation in their top hours (That is, they have a relatively flat peak) that even the residential DR reduction of 131 MW was enough to push the system peak to the next highest hour. Therefore, for simplicity, the remainder of the scenarios will assume that all DR programs are called for each event day.

First, we looked at what might happen if the only event called was on the system peak day. This resulted in a movement of the system peak day from July 8th to July 9th and moved the peak one hour later to 5 pm. The resulting contributions to this new system peak are presented below in Table 3.

Table 3 New Class Contributions to System Peak: One Event

7/09/2008 5:00 pm DST			
Class	**MW**	**% Contribution**	**Fixed Costs ($)**
Agricultural	1,454	7.2%	3,596,220
Medium & Large General Service	10,662	52.7%	26,363,534
Residential	5,589	27.6%	13,818,920
Small General Service	2,516	12.4%	6,221,327
Total Load	20,221		50,000,000

In this example things do not change too much, but they do change. The new system peak is a day and hour that was similar to the old system peak. The costs allocated to the medium and large GS class decrease by 1.3% of the total, roughly $650,000, while the costs allocated to the residential and agricultural classes each increase by a little less than 1% of the total. The increase in the costs allocated to these two classes is small in relation to the total cost, but it is important to look at the percent change in the amount allocated to each class. The residential allocation increases only about 2.8%. However, the costs allocated to the agricultural class increase over 12%. These increases in allocated costs would have a corresponding increase in the eventual rates calculated for these classes. What is particularly interesting here is that the changes in cost allocations are not necessarily intuitive. Because the DR impacts actually move the system peak to a new day, we see both the residential class and the agricultural class having more costs allocated, and the medium & large GS and the small GS classes having fewer costs assigned. This change is driven mainly by the peak hour moving one hour later in the day (from 4:00 pm to 5:00 pm, closer to the end of the business day). Note that even though the residential class provides significant DR, reducing the peak for the system, their percentage of the new peak is higher, with a corresponding increase in costs allocated.

So let's consider another example. If more than one event is called and we are good at calling events, we could call events on the two highest days. What happens to the system peak now? In this case the new system peak becomes the third highest peak day, August 29th at 5 pm. Table 4 shows the new contributions to system peak, for that day and time.

Now things are getting even more interesting. The contributions for August 29th change more relative to those on the original peak day. Here the medium and large GS customers are allocated an additional 1.5% of costs which totals about $700,000 dollars. Like the first example, the residential class also gets a small increase in the allocation of costs. Interestingly here, the two classes without DR programs are those that are helped. The allocation to the small GS class is reduced by about 1% of the total, corresponding to about $500,000 or 8% of their allocated costs. But the real winners in this example are the agricultural customers. The agricultural class gets a 15% reduction in their allocated costs. They are not likely to complain about this. However, if a new system peak day increased their allocated costs by 15%, it would be certain to garner some attention.

Finally let us consider one last example, hitting 3 of the highest 4 days with events. Here the results are perhaps even more unexpected. Table 5 presents the new allocations with events called on the three highest days.

Table 4 New Class Contribution to System Peak: Two Events

8/29/2008 Hour Ending 5:00 PM			
Class	**MW**	**% Contribution**	**Fixed Costs ($)**
Agricultural	1,097	5.4%	2,716,236
Medium & Large General Service	11,200	55.5%	27,729,854
Residential	5,537	27.4%	13,709,416
Small General Service	2,361	11.7%	5,844,494
Total Load	20,195		50,000,000

Table 5 New Class Contribution to System Peak: Three Events

7/10/2008 Hour Ending 4:00 PM			
Class	**MW**	**% Contribution**	**Fixed Costs ($)**
Agricultural	1,340	6.7%	3,348,705
Medium & Large General Service	10,802	54.0%	26,999,533
Residential	5,336	26.7%	13,337,241
Small General Service	2,526	12.6%	6,314,521
Total Load	20,004		50,000,000

The allocations in Table 5 are nearly identical to the allocations on the original peak day. This tells us that when the system peak day changes because of an event, the results are unpredictable. In one case, allocations of fixed costs changed dramatically for all classes, and in another the allocations barely moved. In each case we discuss here, the system peak day changes as a result of the event. We did not explore an example that changed the peak to a different hour on the same day, because that did not happen with our "system." How the peak date and time change depends on the variability in the system load across hours on the same day and peak hours on top days, and on the timing of events and magnitude of impacts. One utility might see a the system peak hour move consistently to the off-peak period while another, like PG&E in this example, may be more likely to see the system peak hour move to a different day around the same time.

Table 6 summarizes the allocations for the four different scenarios to facilitate comparison.

Table 6 Comparison of Allocations Across All Scenarios

	No events	One event	Two events	Three Events
Agricultural	6.4%	7.2%	5.4%	6.7%
Residential	26.9%	27.6%	27.4%	26.7%
Medium & Large General Service	54.0%	52.7%	55.5%	54.0%
Small General Service	12.7%	12.4%	11.7%	12.6%

These examples show how unpredictable changes in allocations resulting from DR events on peak days can be. They are dependent on the number and timing of events called in each season, and the tendency of the peak hour to shift times and days. One could imagine that if PG&E decided to call ten events each season and ended up calling those events on the 7 highest days, or even the 5 highest days, the new system peak day and time could be very dissimilar to the original system peak. Taking the example further, having the system peak move from the original day year after year in different ways might actually cause large changes in allocation factors from year to year, resulting in confusion in price signals to rate classes, and potentially rate shock. To reiterate, it is important to remember that these changes in allocations are only due to the choice of which days were event days, and not the result of any other changes in usage.

Many of the utilities we spoke with asserted that since they used allocation methods other than a 1CP that this would not be as much of a problem for them. We argue that in a world where calling multiple DR events each summer is common and those DR impacts are significant, averaging methods won't offer much protection from this issue. The impacts presented in the above examples amount to a mere 2.8% of system load, yet they were still enough to change allocation factors unpredictably. Most utilities are targeting 5% of total peak load or more for their total DR portfolio, and most aim to call their programs during the highest load days or top load hours. If a utility using a 4 CP method calls 12 events in a season and hits 2 or 3 of those four CP days, those DR impacts are likely to change the day and/or hour of the monthly peak, therefore changing the 4 CP average. The effects might be less drastic, but depending on how different the new peak is from the old peak, they could be significant. Utilities using a Top 100 hours allocation are arguably more sensitive than a utility using a 4 or 12CP allocation. A utility using Top 100 hours allocation, with 60 event hours per season, could have events on 40 of the top 100 hours. That could change allocations based on the top 100 hours fairly substantially, depending on the system load duration curve for that particular utility. The more concentrated the top hours are and the faster the curve drops off, the more the DR impacts will affect the Top 100 hours allocation method.

Treating DR Impacts Consistently

Aside from the adverse or unpredictable effects on cost-of-service allocators, there is a matter of principle. DR impacts should be treated consistently, in all three areas. If a program is designed as a resource, and the impacts are included (or are planned for) in the resource planning process, then they should also be treated like a resource in cost-of-service calculations. If the system operator chooses to meet a load requirement with a combustion turbine rather than a DR program, then that load would remain on the system and the true system peak would remain unchanged. It might be helpful to think of an event-based or dispatchable DR program like a phantom generator that exactly matches a small chunk of load. The load that is met with a DR resource still exists, and would have existed without the program. If the programs are not called on the system peak day, generation will be needed to fill the load requirement.

It is important both for the utility in general and the cost-of-service process to ensure that peak loads are measured accurately. This raises the importance of accurately estimating load impacts of DR programs and using appropriate baselines, since that is what determines what load is added back in to the class and system loads. In order to assure the integrity of the ratemaking process, and not leave the utility open to criticism from interveners, the load impact estimates must be accurate and unbiased. However, is it important to note that using any reasonable estimate is better than doing nothing. If no load is added back in, the assumption is that the load reduction is zero – which is clearly not a reasonable estimate in most cases.

Summary and Considerations

For both correct cost-of-service allocations and the integrity of the system peak load estimates, it is important the DR program impacts are accounted for and added back in to class and system loads. Fundamentally, adding the load back in is the only way to get to accurate allocation factors for cost of service. Not adjusting loads to account for DR impacts may (in cases where a class with DR participants is allocated less cost) be seen as "double crediting" participants. Unpredictable changes in cost allocators resulting from not adjusting loads will inevitably lead to difficulties for the utility. Any utility that plans on using DR to meet future load requirements will be faced with this issue eventually.

The bottom line is this: it is important to treat the DR programs and their impacts consistently. If a DR program is designed as a resource and used as a resource, it should be treated and analyzed as a resource across the board, including for cost allocation.

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Phone interviews were conducted in July-September 2009 with BC Hydro, Idaho Power, NV Energy, Oklahoma Gas & Electric, Pacific Gas & Electric, Public Service Company of New Mexico, Puget Sound Energy, San Diego Gas & Electric, Southern California Edison, and Xcel Energy.

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