Notes regarding submitting comments on this Draft Work Product:

Comments are Due February 7, 2018.

Comments shall be no longer than 5 pages.

Comments should be submitted to LDBPcomments@ebce.org

Demand Response Program Opportunities

for

East Bay Community Energy

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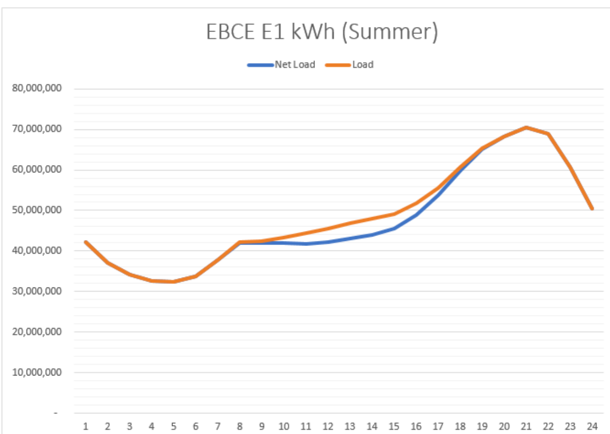
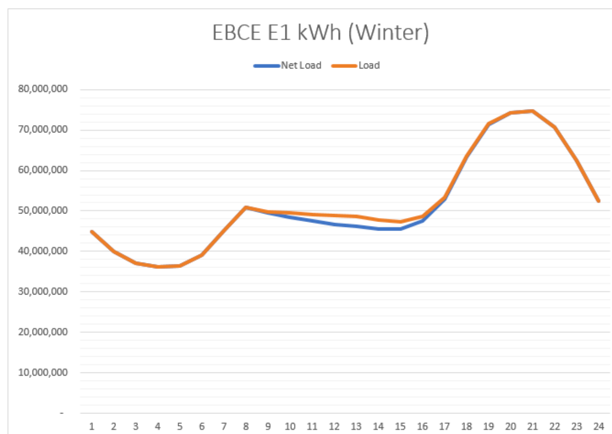
INTRODUCTION

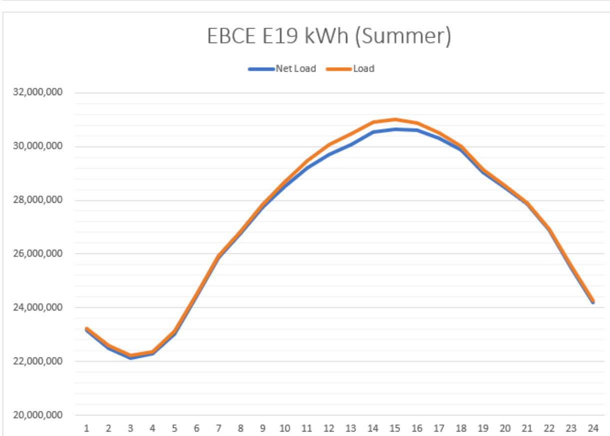
This report provides a high-level approach to deploying demand response in Alameda County. Demand response ("DR") can reduce operating costs for the CCA, provide important resources for reliability, help defer upgrades to generation, transmission and distribution systems, and deliver economic benefits both to customers and to load-serving entities.

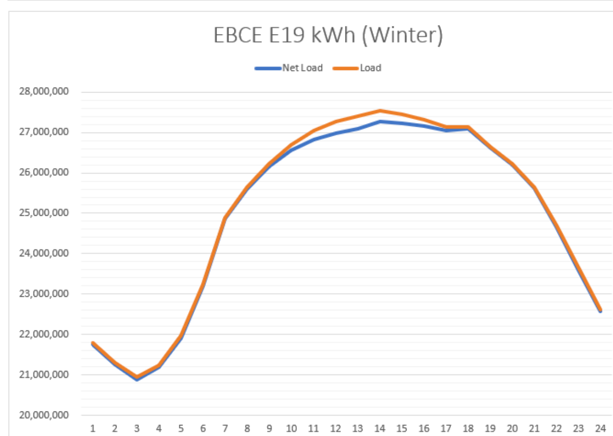
Fundamentally, demand response is needed due to mismatches in the supply and demand for electricity. Demand response is an attempt to either smooth out aggregate demand or shift aggregate demand to correspond with periods of high supply.

When deciding how to build demand response offerings, a utility provider should consider factors such as the types of loads in the service territory, end-user demographics and behavior, current rate structures, generation capacity, and available enabling technologies. Hourly load profiles are a good place to start. Below are load profiles for the most common rate tariffs in Alameda County:[1]









[1] These load curves for EBCE's E19 rate category were developed by the LDBP Project Team using data provided by PG&E under the CCA Info Tariff. They were constructed using Item 17 data, which is the Advanced Metering Infrastructure (AMI) 60-minute and 15-minute interval data.

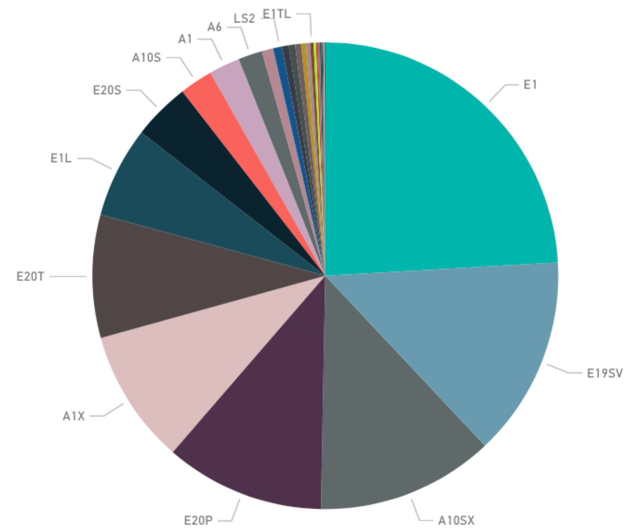


Figure 1: EBCE load by rate tariff

The pie chart at left shows the relative contribution of those rate tariffs to the aggregate load in Alameda County. The E1 rate tariff is predominant for residential customers and shows a large peak in the evening when people return home from work. The E19 rate tariff is for commercial facilities and shows a smoother peak driven by work day hours. This data is informative in tailoring demand response programs for different customer sectors to target the hours of greatest need in that sector.

It is also important to consider the aggregate load across the system. The graphic below shows the total hourly electricity draw in EBCE territory:

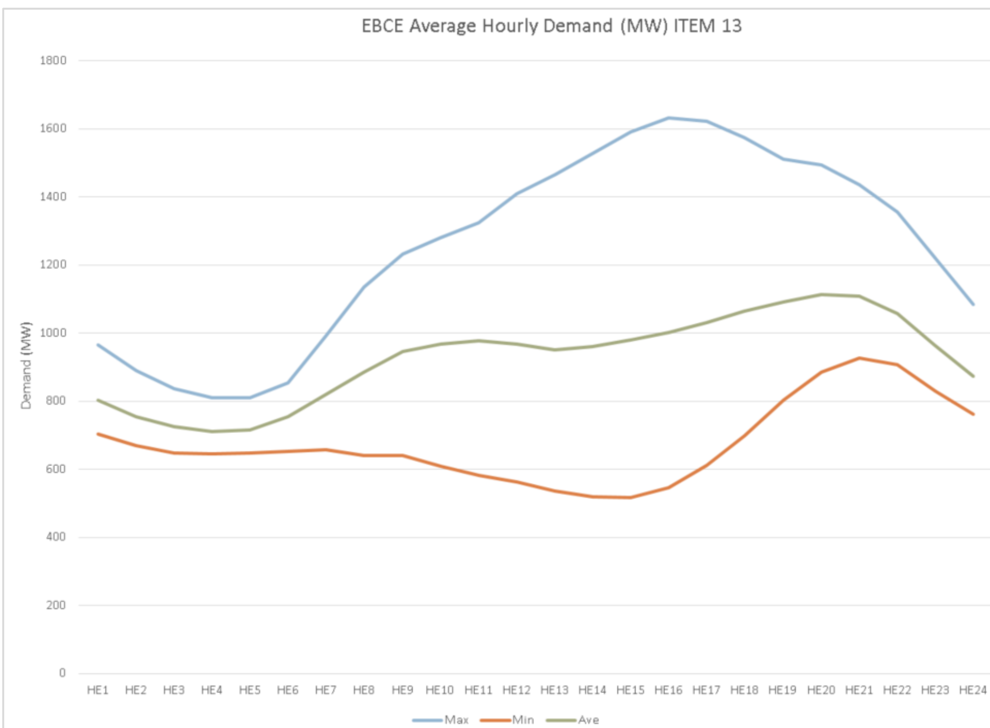


Figure 2: EBCE Item 13 hourly demand (MW)[2]

[2] This load curve was developed by the LDBP Project Team using data provided by PG&E under the CCA Info Tariff (Item 13).

Of course, demand levels alone do not drive demand response policy. Availability of generation and the cost of generation are also critical inputs in determining when it is most economical to shed or shift load. Shifting demand to times when a surplus of renewable generation is available (at no marginal cost) and away from times of highest marginal cost (for example, summer afternoons) are foundational strategies. The cost of electricity varies both hourly and seasonally. The graphic below shows the locational marginal price of energy by day during 2017, and highlights seasonal variation:

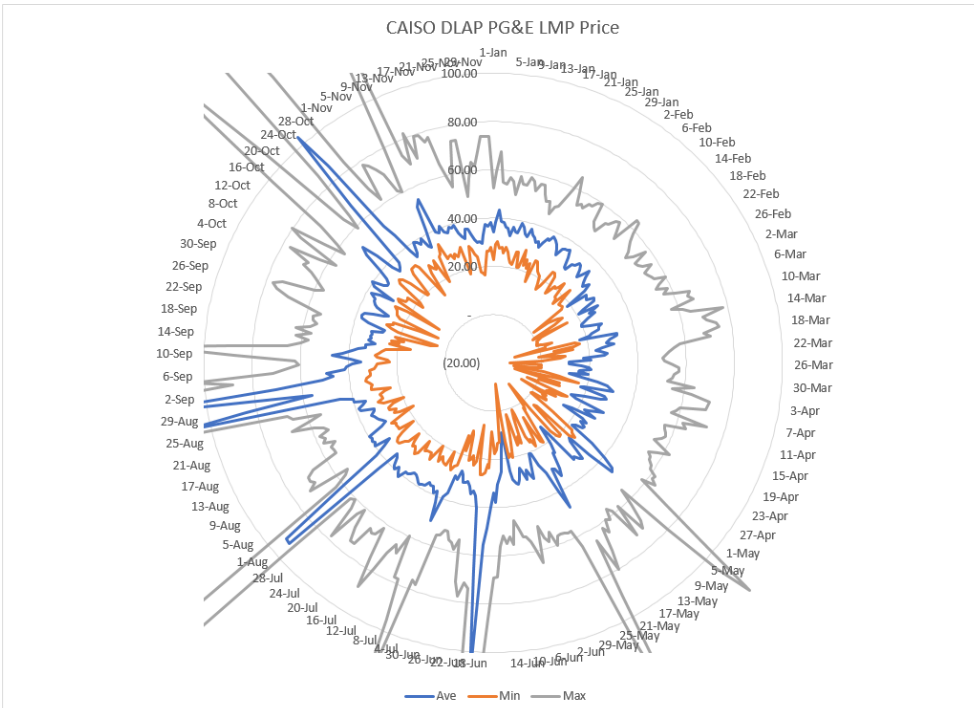


Figure 3: CAISO 2017 Locational Marginal Prices in PG&E territory by day[3]

While the minimum daily price is typically below $0.03/kWh throughout the year, the average and peak prices each day show a wide variance. 2017 peaks occurred during the hottest summer days, but also sporadically during the shoulder months. This seasonal data reveals the critical need for demand response programs that are designed to take affect only during a handful of peak day events each year.

With the need for demand response established, this report will look at the means available for EBCE to meet this need. The following sections of this report will cover, respectively, the types of DR services and the technologies that provide DR, the types of customer facilities that make for logical participants in DR, the programmatic approaches EBCE can use to launch DR, and the revenue opportunities that are available from DR programs.

[3] Source: 2017 CAISO pricing data from OASIS, accessed December, 2017.

DEMAND RESPONSE SERVICES AND TECHNOLOGY

Types of Demand Response

Before addressing the specific technologies that provide demand response, it is instructive to consider the different types of demand response services. A helpful framework was popularized by a CPUC sponsored demand response study led by Lawrence Berkeley National Laboratory (LBNL), which groups demand response services into four categories:

1. "Shed" is load curtailment to reduce peak demand
2. "Shift" is nudging customer load toward times of high renewable generation
3. "Shape" is the re-shaping of customer load profiles
4. "Shimmy" is harnessing loads to mitigate short-run ramps and disturbances

The traditional approach to demand response is via "shed", as for years the greatest need to the electricity grid has been managing peak demand. However, with increasing levels of renewable generation the challenges of the grid have shifted away from peak capacity shortfalls, reducing the value of shed-type resources for serving the CAISO balancing authority over the coming decade and beyond. While "shed" still has locational value, particularly for areas of the grid where the transmission and distribution constrained, the larger opportunity system-wide is in "shift" and "shape" resources that can match load times with peak renewable generation[4].

The LBNL study identified "shift" type resources as having by far the largest opportunity, with around 20% of load being shiftable. The quantity of cost-effective "shift" load is expected to be 2.5 GWh statewide by 2020, and 10-20 GWh by 2025 as renewable penetration increases[5]. Shift resources come from a variety of technology options. The lowest cost options are commercial HVAC and industrial process loads. Once the cost threshold is pushed up to $100/kWh, residential behind-the-meter storage applications have a high potential:

[4] "Shape" refers to *long term* changes in customer behavior, typically driven by time-of-use rate tariffs or other incentive programs. "Shift" refers to actively moving energy consumption toward times of high renewable generation. This report will spend more time directly discussing "shift" resources, where the potential is largest, though in truth the line between "shift" and "shape" is somewhat blurry.

[5] From LBNL's 2025 California Demand Response Potential Study, page 5-17, accessed here: http://www.cpuc.ca.gov/General.aspx?id=10622

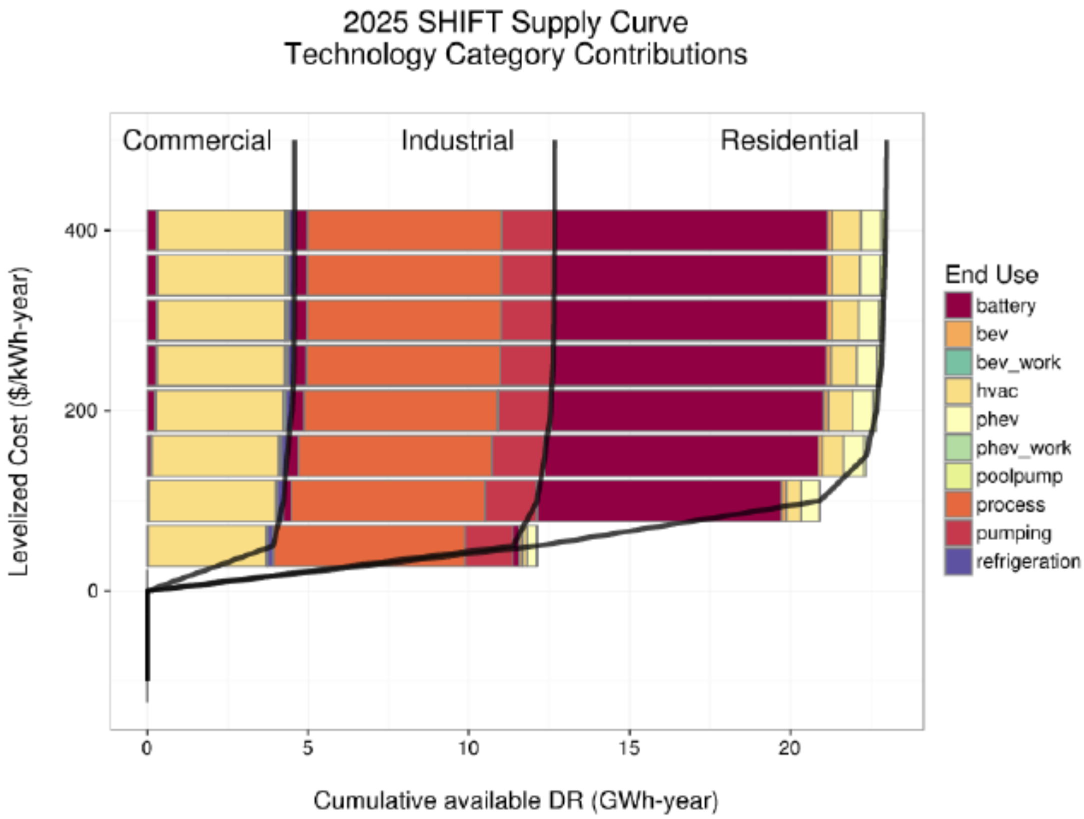


Figure 4: Shift DR supply curve in 2025, with contributions from end-use technologies[6]

The LBNL study estimated the potential for "shed" resources at 2 – 10 GW statewide in 2025[7], though much of this value is in southern California where there are more transmission constraints. The technology options are similar to "shift", with industrial process loads providing the most cost-effective option. Commercial lighting is a new option here, and residential behind-the-meter batteries can also be used for load shedding at higher price points:

[6] From LBNL's 2025 California Demand Response Potential Study, page 5-24.
[7] From LBNL's 2025 California Demand Response Potential Study, page 6-2.

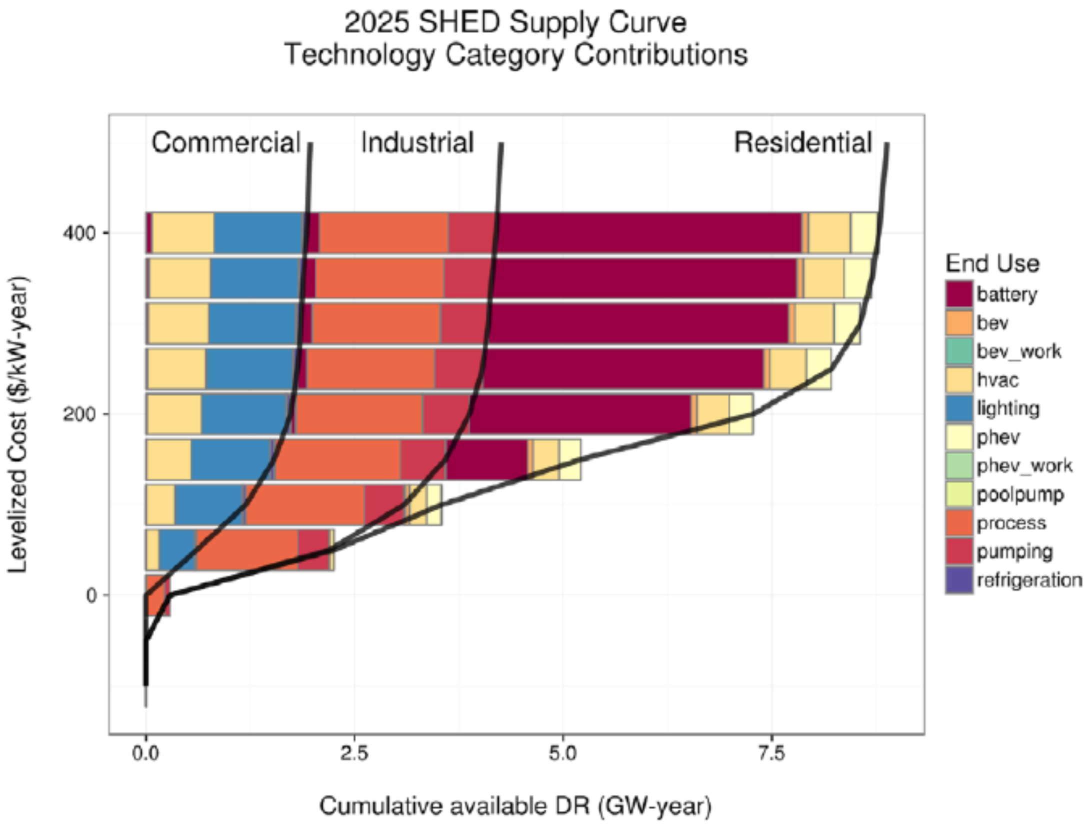


Figure 5: Shed DR supply curve in 2025, with contributions from end-use technologies[8]

Note, the exact technology mix and absolute quantities of demand response deployment in Alameda County is not reflected above, these are statewide totals. These graphs are provided to show the relative prevalence and cost effectiveness of various DR technologies.

[8] From LBNL's 2025 California Demand Response Potential Study, page 5-35.

Demand Response Technologies

With a better understanding of the types of demand response services and what has the most value, we can look at the technologies that provide this value. Many technologies in daily use at customer facilities have significant fringe benefits associated with their demand response potential. The chart below shows this demand response "co-benefit" expressed as a percentage of the initial cost of installing the technology:

End-Use and DR-Enabling Tech	Initial DR Technology Cost Reduction from Co-Benefit	Potential sources of Co-benefits
Commercial and Residential HVAC (EMS and Smart Thermostat)	30%	Energy efficiency and kW reduction
Refrigerated Warehouses	30%	Energy efficiency and kW reduction
Batteries	50%	Consumption optimization, kW reduction, backup energy supply
Agricultural Pumps	75%	Energy efficiency, kW reduction and controllability
Wastewater Process and Pumping technologies	75%	Energy efficiency, kW reduction and controllability
Commercial and Residential BEV and PHEV Level 1 and 2 charging (Fleet and Public)	75%	Fast Charging and controllability
Lighting (Luminaire-level and Zonal)	75%	Energy efficiency and kW reduction

Figure 6: Demand Response technology and application co-benefits[9]

[9] From LBNL's 2025 California Demand Response Potential Study, page 4-8.

Technology Highlight: HVAC control and grid enabled appliances (residential and commercial)

The graphic below highlights the importance of demand response for HVAC applications. It shows the correlation between peak demand and temperature events. Responding to these events is critical for controlling electricity supply costs, as imbalance fees can be substantial when actual load does not line up with projected load.

In this graphic, the daily 2015 EBCE load is overlaid against the high and low temperatures from each day. As expected, load spikes tend to correspond to temperature swings:

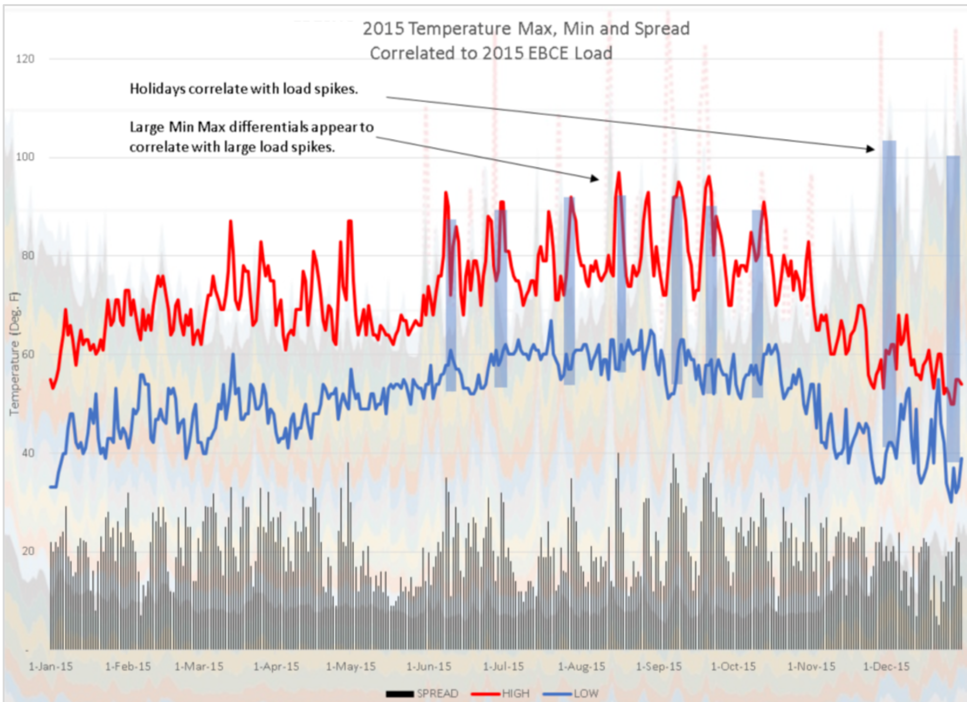


Figure 7: Overlay showing correlation between EBCE's peak loads and high temparature differentials, as well as holidays.

Residential and commercial HVAC have significant untapped potential, particularly as a "shift" resource, to combat this issue. Temperature setpoints can be adjusted during times of peak demand to allow a predefined increase in temperature (during cooling operation) or decrease in temperature (during heating operation). This delays usage until the peak pricing has abated or at least until the new setpoint has been reached. This may be achieved automatically using smart thermostats in conjunction with web enabled control devices.

Sample Program: Toronto Hydro offers the Peaksaver PLUS program. During peak electricity demand periods, Toronto Hydro sends a signal to the enrolled appliance to cycle down the power to the appliance for a short time. Activations are eligible to occur during summer weekday afternoons.

Participating devices:

- Air conditioners are cycled down for 15 minutes out of every 30 minutes.
- Water heaters are turned off a maximum of 4 hours.
- Pool pumps are turned off a maximum of 4 hours. During this time, you will not be able to vacuum the pool.

Technology Highlight: PEV batteries and other storage applications (Residential and Commercial)

Storage devices act as an adjustable load (both as a user and supplier) and can provide load shifting service. While plug-in electric vehicle batteries may be the most prevalent form of behind the meter storage, it is also possible to install dedicated storage devices that have no secondary purpose beyond load shifting and control.

Sample Program: Last year PG&E launched the San Jose DER demonstration project to deploy a fleet of behind the meter batteries in conjunction with solar PV and smart inverters[10]. These resources will be located at customer facilities; PG&E has partnered with installer SolarCity and inverter manufacturer Enphase to sign up customers for the pilot program. A DER management system from General Electric will dispatch the stored energy and test the ability of DERs to provide services via a utility platform. The GE software will allow PG&E to monitor and control the systems.

Sample Program: In addition to the solar + storage program mentioned above, PG&E is also looking to electric vehicles (and reused EV batteries) as a grid resource. The utility partnered with BMW for the iChargeForward pilot project in which BMW committed to providing 100 kW of demand reduction for a 1 hour period when called upon[11]. This demand reduction was provided through a combination of delaying charging for nearly 100 BMW vehicles in the San Francisco Bay Area (contributing around 20% of the kW reduction on average) and a second-life stationary battery system built from reused EV batteries (around 80% on average).

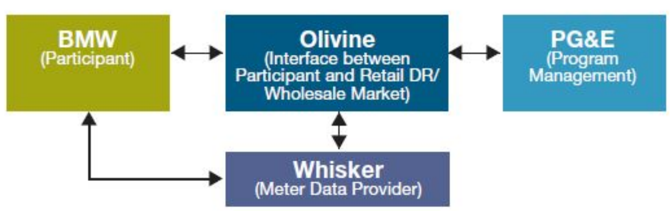


Figure 8: iChargeForward project partners and roles[12]

[10] PG&E news release available at https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20160712_pge_launches_distributed_energy_resource_projects_testing_technology_to_unlock_benefits_of_the_grid_

[11] BMW iChargeForward: PG&E's Electric Vehicle Smart Charging Pilot. Final Report. Published June 2017. Available at http://www.pgecurrents.com/2017/06/08/pge-bmw-pilot-successfully-demonstrates-electric-vehicles-as-an-effective-grid-resource/

[12] From the iChargeForward report, page 7.

The grid services demonstrated in the pilot included day-ahead and real-time signals that were modeled after existing proxy demand resources from the California Independent System Operator (CAISO), in order to test whether these resources could eventually participate at the wholesale level.

Electric vehicle programs are popular, as many customers already own or are interested in owning electric vehicles. As more electric vehicles come online, these types of programs can help utilities stabilize the grid and cope with electricity use spikes in the evening and over-generation of renewables, especially solar, during the middle of the day. Some utilities have rolled out programs to encourage more electric vehicle adoption. Sonoma Clean Power offered rebates on electric vehicle purchases through their EverGreen program, and Avista Utilities (in Washington) has a pilot program in which they are offering to install and maintain over 200 charging stations at residential and commercial properties, with a goal of learning more about the impacts on their grid.

Technology Highlight: Load curtailment (industrial)

Industrial process load is a foundational piece of most current DR programs, primarily as a "shed" type resource. As shown in the "shift" and "shed" supply curves earlier in this report, industrial process load presents one of the lowest cost opportunities for demand response. Large industrial facilities have the greatest opportunity for load curtailment due to the magnitude of power consumption and the often pre-existing infrastructure necessary for communication and control of equipment. These types of systems generally require advanced metering, data accessibility and visualization, and integrated control systems that use the data to respond to peak pricing events. Response can either be manual or automatic.

Sample Program: Alcoa Warrick Operations is an aluminum smelting facility in Indiana that participates in demand response in the Midcontinent Independent System Operator (MISO) market. MISO provides transmission service to 15 states in the central U.S. Smelters generally have a very high load factor. MISO remotely controls 70 MW of smelter load in real time for dynamic grid regulation services. The smelter provides both controllable load (small minute-to-minute variations which are relatively constant) and interruptible load (larger load interruptions of 10's of MW that typically lasts for 30 minutes to 1 hour). The smelter essentially functions as a large capacity, short term battery.

TARGET CUSTOMER BASE

Demand Ratio

A good metric for demand reduction potential is the peak-to-average demand ratio of a customer's load profile. On the CAISO grid in Northern California, the average system-wide value is around 1.8, a number that has been slowly rising over the last twenty years:

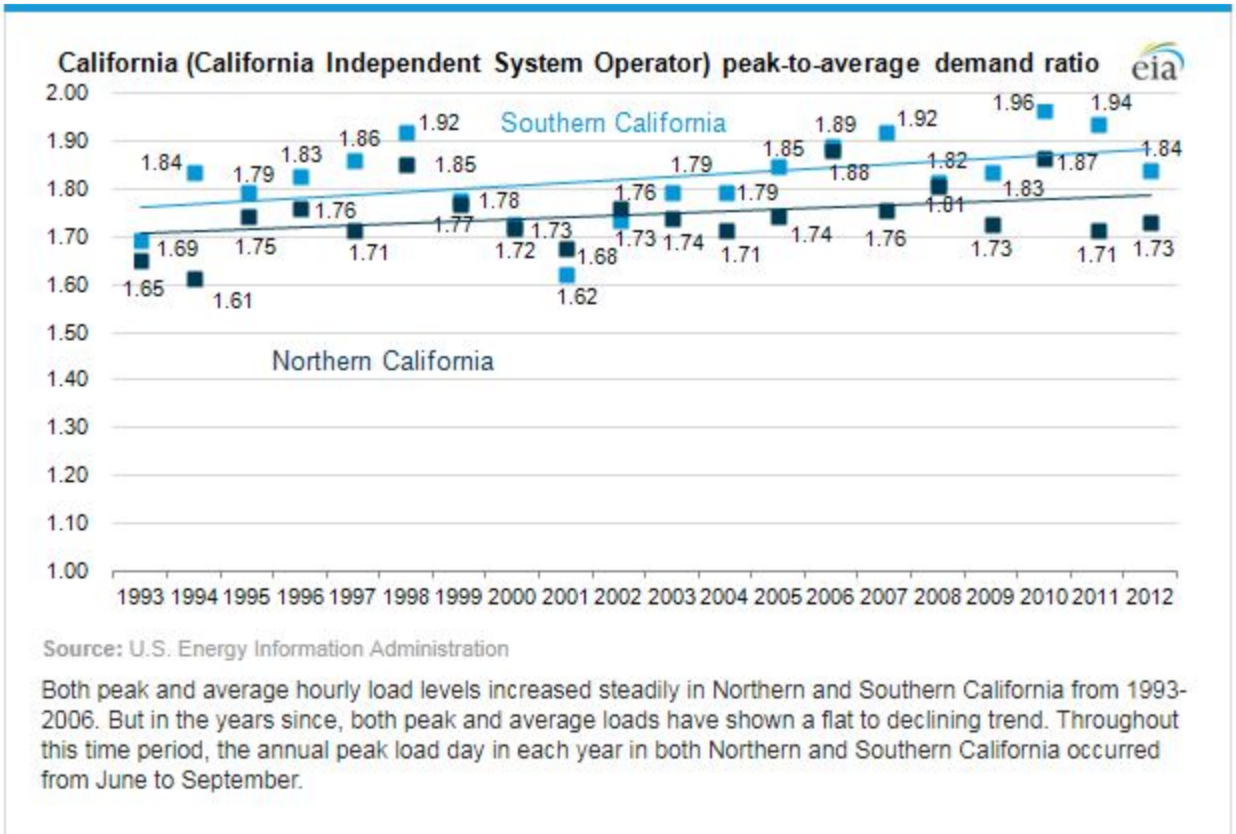


Figure 9: CAISO peak to average demand ratio for the last 20 years[13]

This data is system-wide; individual users can have much higher ratios. The best candidates for demand reduction are customers that have both a high demand ratio and a high baseline usage. To this end, EcoShift analyzed a 12-month history of billing data for the 479 largest electricity users in Alameda County with a focus on demand ratio (the 479 largest users represent 50% of kWh consumption in the County). Some information obtained:

- The average demand ratio for all months is 1.8, and the median is 1.5
- 40% of the customers have at least one month a year with a demand ratio >2
- 20% of all customer-months have a demand ratio >2

[13] U.S. EIA Today in Energy newsletter. Available at https://www.eia.gov/todayinenergy/detail.php?id=15051#tabs_SpotPriceSlider-7

- 4% of all customer-months have a demand ratio >3
- February and August were the months with the highest average demand ratios

The chart below shows the % of all customer-months that have demand ratios at specific levels:

		Demand Ratio			Average Ratio
		>=1	>=2	>=3	
Month	1	100.0%	20.4%	4.6%	1.68
	2	100.0%	18.9%	4.3%	2.29
	3	100.0%	23.3%	5.1%	1.74
	4	100.0%	23.3%	3.8%	1.84
	5	100.0%	24.9%	4.5%	1.85
	6	100.0%	19.8%	4.2%	1.84
	7	100.0%	18.7%	4.0%	1.74
	8	100.0%	17.5%	4.0%	2.12
	9	100.0%	19.1%	5.0%	1.94
	10	100.0%	23.0%	4.0%	1.87
	11	100.0%	19.5%	3.5%	1.72
	12	100.0%	22.0%	4.7%	1.73

Figure 10: Demand ratio by month for the largest electricity users in Alameda County

As seen in the chart above, about 20% of all electricity customers have a peak electricity draw that is at least twice as high as their average draw, and around 4% of customers have a peak draw that is triple their average.

The largest users tend to have relatively flat demand ratios. Here are the monthly demand ratios for 8 of the largest customers in the County:

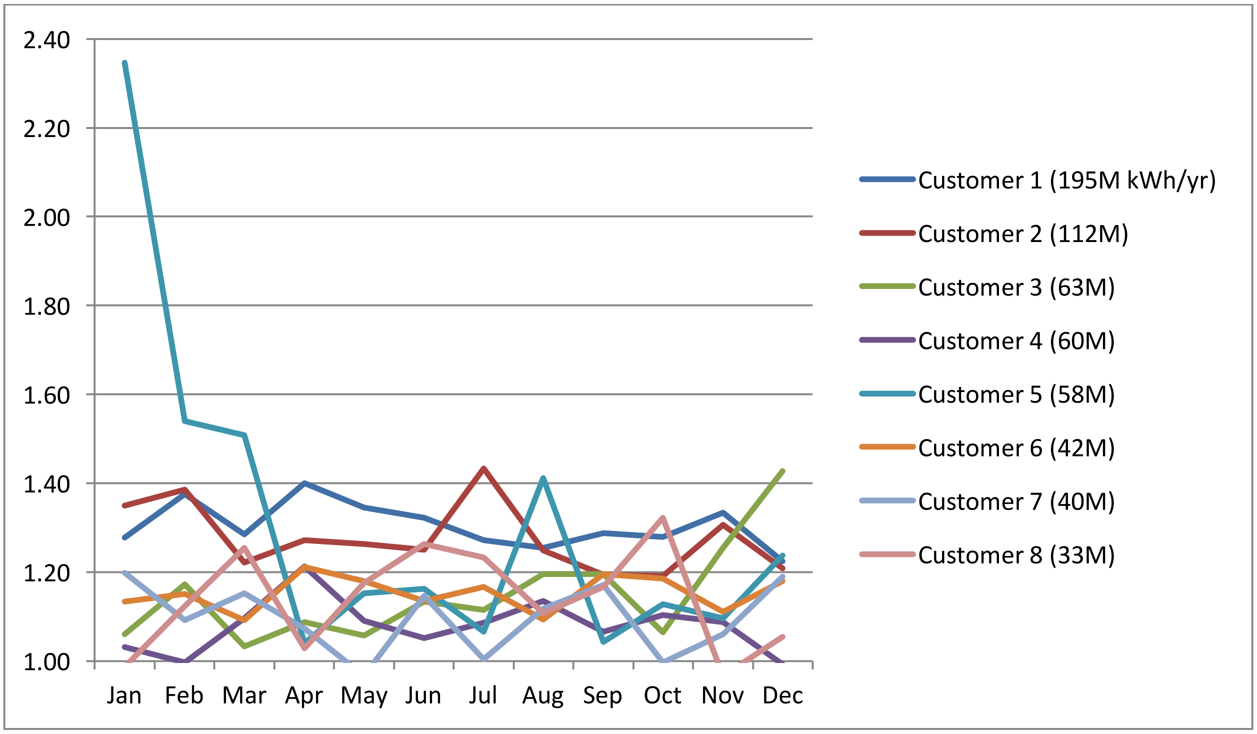


Figure 11: Demand ratios by month for the 8 largest electricity consumers in Alameda County

The best host candidates are those with both a high baseline usage and high demand ratios throughout the year [what about Location/Congestion/Substation, Rate/Cost Savings, LMP price?]. Since any demand response technology put in place at a customer premises will be installed full time, it is optimally placed at a facility that has a relatively high demand ratio during most months (not just 1 or 2 months a year) to maximize savings/revenue.

The following section highlights various facility types that would make good candidates for demand response programs. Though based on actual data, all customer names have been removed to protect privacy.

Candidate Host Facilities in Alameda County

I. Commercial Facilities

DR Technology Options: HVAC control

- Example 1[14]: East Bay Supermarket- 1290 kW average draw, 2380 kW peak demand

Similar facilities: Large retail shopping stores

II. Educational Facilities

DR Technology Options: HVAC control, PEV stations, storage applications

- Example 2: East Bay College- 385 kW average draw, 1500 kW peak demand
- Example 3: East Bay College- 375 kW average draw, 1250 kW peak demand

Similar facilities: Community colleges, large primary and secondary schools

III. Industrial Facilities

DR Technology Options: load curtailment, PEV stations, storage applications

- Example 4: East Bay Industrial- 1070 kW average draw, 3450 kW peak demand
- Example 5: East Bay Industrial- 335 kW average draw, 2600 kW peak demand
- Example 6: East Bay Industrial- 670 kW average draw, 2560 kW peak demand

Similar facilities: Foundries, mining operations, large industrial and manufacturing plants

IV. Municipal Facilities and Utilities

DR Technology Options: HVAC control, PEV stations, energy storage applications

- Example 7: East Bay Utility- 1830 kW average draw, 7400 kW peak demand
- Example 7: East Bay Municipal- 880 kW average draw, 1670 kW peak demand
- Example 8: East Bay Utility- 250 kW average draw, 500 kW peak demand

Similar facilities: Ports, sports venues, convention centers

V. Power Plants

DR Technology Options: Energy storage applications, PEV stations

- Example 9: East Bay Power Plant- 840 kW average draw, 14 MW peak demand
- Example 10: East Bay Power Plant- 450 kW average draw, 3690 kW peak demand

Similar facilities: Combined-cycle natural gas-powered facilities, fuel oil-powered facilities, cogeneration facilities

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[14] Note- In accordance with state rules and regulations governing the handling of utility customer data (i.e., CPUC Decisions 11-07-056 and 12-08-045, the 15/15 Rule, etc.), the Examples in this section (including Figure 11 above) have been anonymized to protect confidentiality. Detailed, customer-specific data and information relating to these high-priority candidates for Demand Response programming identified by the LDBP analysis will be provided to EBCE and its staff upon completion of the project to assist in customer outreach and engagement for any programs offered by EBCE.

PROGRAMMATIC APPROACHES

A phased approach to offering DR services to customers would allow EBCE to have a DR product available soon after launch while gradually building up the in-house capabilities to eventually have a robust set of programs for customers. The early years of this phased approach would see EBCE primarily serving as a conduit for existing programs available through PG&E and 3rd party providers, while subsequent years would see EBCE start to have their own offerings, initially leaning on the experience of partners and eventually developing the capabilities to offer DR products and programs directly to customers.

Phase 1: EBCE acts as a pass-through entity for existing PG&E DR programs

In June 2016, the California PUC approved a PG&E proposal for $60M in demand response programs and activities for 2017. PG&E offers several demand response programs and incentives at the retail level.

Programs:

- Peak Day Pricing[15] (PDP) offers business customers lower electricity rates from May 1 to October 31 in exchange for significantly higher rates (around $0.85/kWh) from 2pm to 6pm on 9 to 15 peak days per year. Notification is sent the day before a peak day event (typically hot summer days) with the goal for the customer to reduce usage during this time.
- Base Interruptible Program[16] (BIP) is a more involved version of the peak day program. It also offers lower utility rates in exchange for load reductions during peak times, but with more stringent requirements for load reduction in exchange for higher regular savings. It is designed for larger users who have an average monthly demand of at least 100 kW. As short as a 30-minute notice is given for curtailments, with event frequency limits of 4 hours per event, 1 event per day, 10 events per month, and 120 hours per year. For customers, monthly incentive payments are proportional to the load reduction amount (in kW) to which the customer commits.
- Scheduled Load Reduction Program[17] (SLRP) is a version of load reduction which gives the customer more control. It allows participants to choose their load reduction amount and their load reduction time (4 hour blocks during weekdays). The customer earns $0.10/kWh for reducing load during the selected time(s) each week. There are no penalties for non-reduction. This program is also for larger customers as the load reduction amount must be at least 100 kW. The program is offered June through September.

[15] https://www.pge.com/en_US/business/rate-plans/rate-plans/peak-day-pricing/peak-day-pricing.page
[16] https://www.pge.com/en_US/business/save-energy-money/energy-management-programs/demand-response-programs/base-interruptible/base-interruptible.page
[17] https://www.pge.com/en_US/business/save-energy-money/energy-management-programs/demand-response-programs/scheduled-load-reduction.page

- Optional Binding Mandatory Curtailment[18] (OBMC) Plan is different from the others as it does not offer a financial incentive for participation, but rather offers exemption from rotating outages. To qualify, customers must reduce their load by up to 15% below an established baseline within 15 minutes of notification. The events can occur at any time. This program is administered at the circuit level, so customers sharing a circuit must coordinate with their neighbors.
- Capacity Bidding Program[19] (CBP) is a program run by 3rd party aggregators. Each aggregator has their own program rules and recruits customers. Universal features include operation from May through October and eligibility for agricultural, commercial, and industrial customers only. There are currently 9 PG&E qualified aggregators.

Incentives:

- Automated Demand Response[20] (ADR) pays the customer a financial reward for installing energy management technology that enables demand response at the facility. After installing the electric controls, the customer receives automated event signals from PG&E which initiate pre-programmed DR strategies. The incentive payment depends on the technology (lighting pays the highest) and the customer must be enrolled in a PG&E DR program.
- Permanent Load Shift[21] via Thermal Energy Storage (PLS-TES) provides large financial incentives for installing equipment that facilitates permanent load shifting using TES technologies. TES shifts cooling loads to off peak hours by storing energy in a cold water or ice tank.

EBCE could work on behalf of large commercial and industrial users to identify and join appropriate programs for that customer. This feasibility work would likely be performed by a third party. Customers could be given incentives to participate (such as rebates on DR equipment and upgrades) or take on the capital investment themselves with the intent to make their return through utility bill savings, depending on the program structure. There are also 3rd party Demand Response Providers ("DRPs") who have DR programs that compete with PG&E's offerings. As of September 2017, the CPUC lists 15 registered DRPs[22] (11 of which serve PG&E territory). EBCE could perform their own reconnaissance to determine the most favorable programs, or direct customers directly to PG&E's offerings.

In addition to targeting large commercial and industrial candidates (see sample candidates in Section 2 of this report), there are some 3rd party programs that may target smaller commercial and residential users as well. 7 of the 15 CPUC-registered DRPs currently serve this segment. While working 1:1 with these customers would not be an efficient exercise for EBCE, mass

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[18] https://www.pge.com/en_US/business/save-energy-money/energy-management-programs/demand-response-programs/optional-binding-mandatory-curtailment-plan/optional-binding-mandatory-curtailment-plan.page
[19] https://www.pge.com/en_US/business/save-energy-money/energy-management-programs/third-party-programs/capacity-bidding.page
[20] https://www.pge.com/en_US/business/save-energy-money/energy-management-programs/demand-response-programs/automated-demand-response-incentive/automated-demand-response-incentive.page
[21] https://www.pge.com/en_US/business/save-energy-money/energy-management-programs/demand-response-programs/permanent-load-shift-thermal-energy-storage/permanent-load-shift-thermal-energy-storage.page
[22] Find the list of registered DRPs at http://www.cpuc.ca.gov/General.aspx?id=6306

marketing campaigns could be an effective way to inform this customer segment of their opportunities.

EBCE could benefit from being a pass-through entity in multiple ways. While 3rd party DRPs serve as the wholesale facing entity bidding into the CAISO market, they sometimes partner with separate entities known as "aggregators" who act on the retail side to engage and enroll customers. If EBCE were playing this role on the retail side, the DRPs may be willing to pay for these services.

In addition to potential compensation for acting as an "aggregator", EBCE would benefit through lower energy and capacity procurement costs.

Phase 2: Partner with demand response product and service partners

Once EBCE is established and ready to take on a more active role in DR services, developing partnerships with experienced third party DR providers would allow EBCE to lean on the experience of DR vendors, many of whom have worked with other utilities, to launch DR programs quickly and effectively.

Sample Partnership: MCE's My Energy Insight[23], a direct load control DR program, uses AutoGrid's Demand Response Optimization and Management System™ (DROMS™) to connect to program participants' smart thermostats and pool pumps via the Energy Internet. If CAISO electricity market prices go above a certain threshold, AutoGrid DROMS sends a signal in real-time to participants' smart thermostats and pool pumps.

MCE is using the pilot program to reduce energy procurement expenses during times of peak energy demand. The DROMS software provides highly targeted and reliable demand reduction. MCE will also study whether the program can provide an additional revenue stream by bidding demand response capacity from the customer-owned DERs into the CAISO market.

This type of partnership allows for quick rollout and easy management of a new DR program. Beyond the equipment and software, the third-party provider can also handle the enrollment and customer experience through established channels. The program can be expanded to other types of loads (water heaters, EV chargers, etc.) once established.

[23] View the press release at http://www.auto-grid.com/news/mce-selects-autogrid-flex-for-demand-response-and-distributed-energy-resource-management

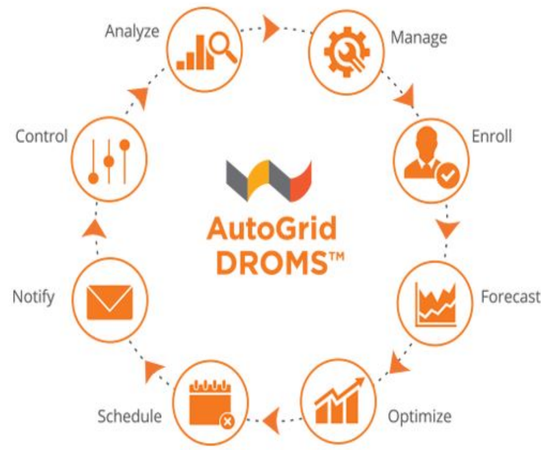

Figure 12: Features of the demand response optimization and management system[24]

Sample Partnership: Another provider of demand response technology is Ice Energy, whose distributed ice battery storage solutions[25] shift air conditioning load to nighttime hours. The Ice Bear charges by making ice during off-peak hours and discharges by using the stored ice to cool buildings during the daytime (normally corresponding with peak load and peak pricing times). The most common configuration reduces cooling electricity by 95% for a 6-hour period during the day.

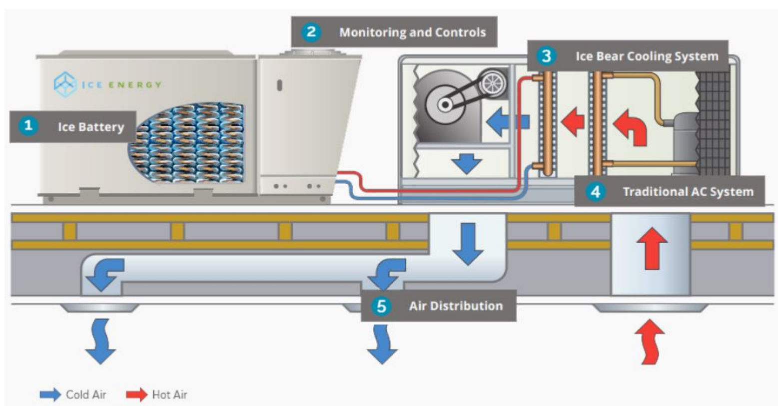

Figure 13: Ice battery power flow schematic[26]

While most pilots have been at larger commercial and industrial facilities, there is a residential product as well. This type of partnership would be very streamlined to roll out, as it does not require new rate tariffs or active management of load. It delivers a product that runs automatically during times when there are frequent spikes in electricity demand and cost. Customers can be incentivized to participate via upfront rebates on the installation cost, or the

[24] http://www.auto-grid.com/products/droms/
[25] https://www.ice-energy.com/technology/
[26] https://www.ice-energy.com/technology/

utility can subsidize the installation cost by signing a power purchase agreement with Ice Energy. This is the model for a recent deployment in Southern California, where SCA signed a 20 year PPA with Ice Energy, and commercial and industrial customers received the product at no cost.[27]

Sample Program: Marin Clean Energy (MCE) and Sonoma Clean Power both offer electric vehicle charging programs. MCE's SmartCharge EV[28] program was launched in 2017. It uses the eMotorWerks JuiceNet® cloud based platform to manage EV charging stations, allowing the chargers to respond to grid load and pricing conditions. As with most DR programs, the primary benefit to the utility is reduced energy procurement costs. Participating customers receive discounts on EV charging stations and cash back for avoiding charge during peak usage times.

Sonoma Clean Power's program provides discounts on JuiceNet enabled chargers. CleanCharge software allows the chargers to adjust in response to grid signals during peak energy times; the software can either defer charging to a later time or simply slow the rate of charge. The customer can override this from a smartphone app if they need to charge immediately. The system can respond to grid events in 3 seconds, allowing the utility rapid-response load shifting capability.

Phase 3: EBCE develops their own DR customer program offerings

While it may be easier to piggy-back on existing programs initially, our findings indicate the more effective long term strategy is to bring DR programs in house. This could include launching DR programs which mirror existing offerings, developing new programs, and using rate tariffs to encourage participation.

One key motivation for developing programs in house is the ability to tailor them to the EBCE load scenario, which may not align with the load scenario that existing programs from PG&E and others are designed to counter. The table below illustrates this point. The table shows the percent of peak capacity allocation factor ("PCAF") in 19 divisions in the PG&E territory for the summer months (June through September). The PCAF is a concept developed by PG&E which is designed to quantify the relative need for capacity reductions during any given hour; essentially, a measure of how high the load is during that hour. It is instructive to see where the peaks occur in the East Bay (4th column from the left) as compared to the rest of PG&E territory:

[27] http://go.nrgbusiness.com/l/72682/2016-04-13/4kqz4p
[28] https://www.mcecleanenergy.org/news/smartcharge/

Hour Ending at		DE_ANZA		EAST_BAY		HUMBOLDT		LOS_PADRES		NORTH_BAY		PENINSULA		SAN_FRANCISCO		SIERRA		STOCKTON		Weighted
Summer	CENTRAL_COAST		DIABLO		FRESNO		KERN		MISSION		NORTH_VALLEY		SACRAMENTO		SAN_JOSE		SONOMA		YOSEMITE	All
1:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
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6:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
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12:00:00 PM	5%	1%	0%	5%	0%	1%	1%	3%	1%	0%	0%	6%	0%	7%	0%	0%	1%	0%	0%	2%
1:00:00 PM	5%	2%	0%	6%	1%	2%	2%	4%	2%	1%	0%	6%	0%	8%	2%	0%	2%	0%	1%	2%
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9:00:00 PM	7%	2%	6%	4%	8%	10%	9%	5%	5%	2%	10%	3%	9%	0%	4%	6%	4%	8%	9%	6%
10:00:00 PM	3%	1%	0%	2%	3%	5%	4%	2%	2%	1%	3%	0%	2%	0%	1%	1%	2%	3%	4%	2%
11:00:00 PM	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Figure 14: Peak capacity allocation factors in the PG&E territory[29]

In the East Bay, the peak load tends to occur earlier in the afternoon. This data is critical to designing demand response policies. For instance, a time-of-use rate tariff could be established with peak pricing during the red hours and partial peak pricing during the yellow hours.

When thinking about the types of DR programs to offer, it is helpful to classify these programs as either a) price-based, or b) or quantity-based. Price-based programs attempt to reduce consumer energy demand through market-based price signals. Quantity-based programs attempt to lower participant demand through direct utility control of certain loads, such as air conditioners, electric water heaters, and/or pool pumps.

Price-based programs

Price-based programs should be the foundation, and can encourage usage shifting over the long term into periods where more generation is available. This is the "shape" type DR discussed earlier in this report, affecting customer behavior by shaping customer load profiles to the desired result. Price based programs will typically be implemented via rate tariffs, either as base rates or as riders that customers can opt into.

One key advantage of these rate tariffs is the ability to customize the tariff to operate over different time scales. Time-of-use base rates are long term and permanent, while many optional riders such as peak day pricing programs are temporary and relatively infrequent. Looking at the five PG&E demand response programs summarized in Programmatic Approaches Phase 1, they vary from fleeting (the OBMC program which only takes affect during rotating outages) to occasional (the PDP which is limited to 15 peak days per year or the BIP program which is limited to 120 event hours per year) to relatively constant (the SLRP load reduction program which occurs during select 4-hour weekday blocks for 4 continuous months). This

[29] PG&E, February 26, 2016- What Factors Should Affect Selection of Time- of-Use (TOU) Periods?, accessed here: www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=12347

flexibility provides the electricity provider options for tailoring the price-based programs to meet the need.

Approaches for EBCE to build demand response programs into their tariffs include:

- Establishing time-of-use base rate structures to encourage long term “shape” type demand response
  - Time-of-use (TOU) programs offer consumers varying electricity rates depending on the hour of the day in which the energy is consumed, typically in two to three rate tiers and often with both seasonal and weekday/weekend dependencies. While TOU programs may not encourage reduction of total energy consumption, the fixed rate pattern does result in persistent load shifting to off-peak times.
- Establishing optional riders that encourage “shift” type demand response
  - Rate tariff riders allow the utility provider to more actively realize load reductions from customers when energy costs are high.
  - The current PG&E demand response programs listed in Programmatic Approaches Phase 1 of this report are all examples of rate tariff riders that drive temporary load shifting. These shifts can be fleeting (designed to occur only during outages or sporadic peak pricing events) or relatively constant (taking effect seasonally).
  - There is significant flexibility in the design of these rate tariff riders. This includes variance in the amount of advance notice (OBMC is 15-minute notification, PDP is day ahead, and SLRP occurs on pre-determined days) and variance in the incentive to participate (lower rates year-round, payment for load reduction, up-front rebates on energy efficient equipment, or simply exemption from outages).
  - To encourage participation, these riders are often offered risk free in the first year, meaning customers are guaranteed not to pay higher utility costs than they would without the rider. In order to promote other program offerings, customers can be required to opt in to a demand response program in order to participate.
  - In order to ensure the program is a win for EBCE, payments could be set in proportion to actual savings in energy procurement. A key consideration for this type of program is the protocol for measuring curtailment, which normally involves establishing a historical baseline against which reduction can be measured. Access to AMI data and detailed customer usage patterns will allow EBCE to both establish baselines and perform measurement and verification on event days.

Building DR programs into rate tariffs will allow participation to be more in line with EBCE’s needs (e.g., aligned with their peak energy demand times or times when capacity is in short supply) rather than relying on PG&E’s program structure, or the ISO market structure, to suit EBCE.

Sample Program: EV specific rate tariffs[30] are offered by PG&E. These are non-tiered rate plans, meaning customers don't risk getting pushed into a more expensive electricity tier by charging their vehicles. They are also time-of-use, incentivizing owners to charge their vehicles after 11pm. Customers can install a dedicated meter for their vehicle or add it to their existing meter. Smart rate tariff design helps the utility by reducing peak load and saves the customer money on charging. Marin Clean Energy has followed suit with a similar rate[31] for EV owners mirroring the PG&E program.

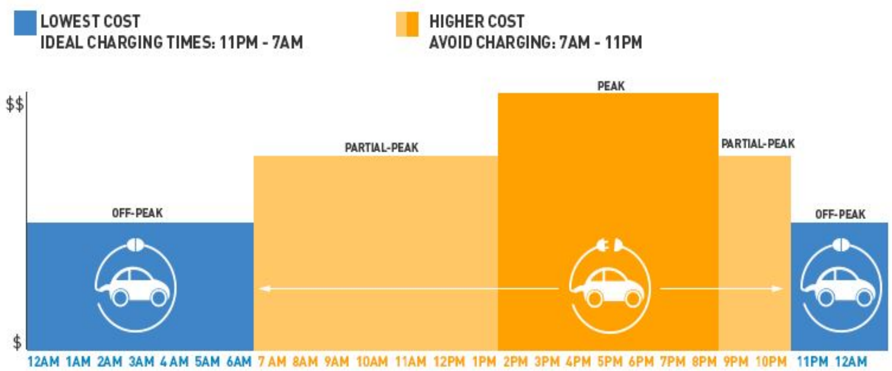

Figure 15: PG&E's time-of-use bins for electric vehicles[32]

Quantity-based programs

Quantity-based DR programs typically involve the utility having direct load control over customer devices. The utility remotely controls loads at consumer sites using switching devices installed on particular appliances or loads, and compensates consumers for the opportunity to interrupt part of the load as needed. This compensation could be offered via an upfront payment or upfront rebate on the cost to install the equipment, a payment per event based on the amount of load reduction, or a permanent discount in electric rates as long as participation is active. Direct load control has more potential value compared to price-based programs, since it is dispatchable and entirely under the operational control of the utility.

These programs often involve HVAC, water heater loads, or pool pumps in the residential sector. Several sample programs highlighted earlier in this report feature direct load control of these types of devices, including the Toronto Hydro Peaksaver Plus program and Marin Clean Energy's My Energy Insight.

Electric vehicles are another load type that is becoming popular for demand response load control. Both Marin Clean Energy and Sonoma Clean Power have EV charging programs in conjunction with the JuiceNet platform, as highlighted previously in this report.

[30] View PG&E's EV rate plans at https://www.pge.com/en_US/residential/rate-plans/rate-plan-options/electric-vehicle-base-plan/electric-vehicle-base-plan.page
[31] View MCE's electric vehicle webpage at https://www.mcecleanenergy.org/electric-vehicles/
[32] https://www.pge.com/en_US/residential/rate-plans/rate-plan-options/electric-vehicle-base-plan/electric-vehicle-base-plan.page

For any direct load control program the communications infrastructure is critical. Fast ramping and response is important to successful demand response programs, and traditional smart meter AMI data that uses hourly or even 15 minute pings does not provide adequate granularity into the load situation. Home area network ("HAN") devices are increasingly being used which can obtain signals and communicate in intervals of seconds. Installation of HAN devices on customer premises, initially targeting the with largest high value customers mentioned in the *Target Customer Base* section of this report, could be an effective strategy for engaging with these customers and enabling their participation in a DR program.

Phase 4: EBCE owns BTM assets and acts as Demand Response Provider to ISO

Third parties can also provide demand response outside of utility programs. The Demand Response Auction Mechanism (DRAM) allows third parties to offer portions of their own demand response portfolios directly into the CAISO market.

All CCA's are eligible to become registered Demand Response Providers ("DRPs") with CAISO. There are currently 21 listed[33] DRPs, including MCE Clean Energy (formerly Marin Clean Energy) and Lancaster Choice Energy, the California IOUs, and many 3rd party DR providers.

Participation in the ISO market requires several steps[34] including scheduling coordinator certification (EBCE could either retain the services of an existing SC, and/or become a registered SC to provide these capabilities internally), ancillary services certification, completion of the New Resource Implementation process, installation of ISO-certified revenue quality meters and direct telemetry, and compliance with relevant ISO Tariff and Business Practice Manuals. Building up these capabilities and/or partnerships is a multi-year process in which EBCE would be served to lean heavily on outside parties and experience from prior phases of implementation.

Additional details on this approach are provided in the subsequent section.

[33] Download the list at https://www.caiso.com/Documents/ListofDemandResponseParticipants.pdf
[34] https://www.caiso.com/participate/Pages/Load/Default.aspx#PL

REVENUE OPPORTUNITIES FOR EBCE

Revenue Opportunity 1: Act as a Demand Response Provider ("DRP") in the ISO market

CAISO's Distributed Energy Resource Provider (DERP)[35] program enables resources such as demand response and storage connected to distribution systems within CAISO's balancing authority area to form aggregations of 0.5 MW or more and participate in CAISO's energy and ancillary services markets.

Both Proxy Demand Resources ("PDR") and Reliability Demand Response Resources ("RDRR") have revenue opportunities with CAISO[36].

Proxy Demand Resources:

- Participates in CAISO similar to a supply resource
- Can bid into day-ahead energy market (100 kW min load curtailment), 5-minute real-time energy market (100 kW min), and day-ahead and real-time non-spinning reserve market (500 kW).

Reliability Demand Response Resources:

- Can participate in day ahead market.
- Can respond to real-time reliability events by delivering "reliability energy"
- Min load curtailment 500 kW. Must be able to fully curtail within 40 minutes
- Length of events 1 to 4 hours.

Both PDR and RDRR are allowed to aggregate to reach size thresholds. Aggregations are required for a single load serving entity; this provides the LSE with visibility on DR awards. To avoid congestion issues, all resources must be within same sub-Load Aggregation Point (there are 24 in CA). Alameda County is split into two sub-LAPs[37], meaning two separate aggregations would be required. A stretch from Hayward to Fremont is in one sub-LAP, with most of the remaining County in the other.

PG&E selects[38] Demand Response providers through a CPUC mandated Demand Response Auction Mechanism ("DRAM"). In 2016, PG&E selected 6 providers for a total of 17.7MW, in 2017 selected 21.4MW, and in the third year of the program selected 80MW for 2018 and 90MW for 2019. Though specific pricing is confidential, it is known that PG&E procured the 21.4MW 2017 allotment within a $12M budget. PG&E is credited for the capacity to help meet their resource adequacy requirements. Participants keep the revenues from the CAISO energy market, though the capacity payments from PG&E are expected to be the larger revenue source.

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[35] www.caiso.com/participate/Pages/DistributedEnergyResourceProvider/Default.aspx
[36] www.caiso.com/participate/Pages/Load/Default.aspx
[37] See "PG&E SubLAP Map" near the bottom of the page at www.pge.com/en_US/business/save-energy-money/energy-management-programs/demand-response-programs/2017-demand-response/2017-demand-response-auction-mechanism.page
[38] www.pge.com/en_US/business/save-energy-money/energy-management-programs/demand-response-programs/2017-demand-response/2017-demand-response-auction-mechanism.page

Though EBCE will not be subject to a similar CPUC requirement to hold an auction, it will be subject to the capacity and resource adequacy requirements that these DR resources can help meet. The auction process and results is instructive for the types of demand response products and providers that can be successful in the CAISO market. The biggest winners for PG&E's most recent auction included solar companies (SunRun, Tesla) and DR solutions providers (OhmConnect, EnerNoc, and AutoGrid Systems), many of whom partner with Olivine as the DR platform provider. PG&E received 83 applications in the most recent DRAM, indicating there is a strong base of providers.

Revenue Opportunity 2: Lower capacity costs to meet resource adequacy requirements

Demand response programs can be cost effective alternatives to procured capacity that would otherwise be needed to comply with California's resource adequacy requirements. California's utilities are required to procure resource adequacy[39] to cover times of peak energy demand. This is typically done through bilateral contracts with gas-fired power plants. A demand response portfolio that can provide a similar response with reliability can reduce the need for these "peaker" plants.

The CPUC ruled that dispatchable DR counts for local capacity requirement in regard to local resource adequacy. Both Sonoma Clean Power and Peninsula Clean Energy have set goals to meet 5% of their total capacity requirements through dispatchable demand response programs (equivalent to 44 MW of peak demand for PCE and 18 MW for SCP). Anticipated capacity requirements in Alameda County per the EBCE Implementation Plan are below:

East Bay Community Energy
Capacity Requirements (MW)
2018 to 2027

Demand (MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Retail Demand	831	1,416	1,419	1,421	1,424	1,427	1,430	1,433	1,436	1,439
Losses and UFE	0	0	0	0	0	0	0	0	0	0
Total Net Peak Demand	831	1,416	1,419	1,421	1,424	1,427	1,430	1,433	1,436	1,439
Reserve Requirement (%)	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Capacity Reserve Requirement	125	212	213	213	214	214	214	215	215	216
Capacity Requirement Including Reserve	956	1,628	1,631	1,635	1,638	1,641	1,644	1,648	1,651	1,654

Figure 16: EBCE's projected annual capacity requirements[40]

[39] http://www.cpuc.ca.gov/RA/
[40] From the EBCE Implementation Plan, August 2017, page 21. Available at https://ebce.org/resources/

The 2016 Resource Adequacy Report from the CPUC showed a weighted average price for RA capacity contracts at $3.10/kW-month[41]. If EBCE were to mirror goals set by Sonoma Clean Power and Peninsula Clean Energy to meet 5% of total capacity requirements through dispatchable DR, this would amount to around 48 MW in 2018 based on the projected capacity requirements above. At an average capacity contract rate of $3.10/kW-month, using DR to cover 5% of total capacity requirements would result in RA procurement savings of around $1.8M/yr. Of course, these savings would need to be netted against the cost of the DR program to arrive at a net benefit.

Revenue Opportunity 3: Decreased energy procurement costs during peak hours

Energy costs will likely be the dominant expenditure for EBCE. Sonoma Clean Power's Implementation Plan from 2016 showed energy costs to far outweigh spending on personnel, programs, G&A, and all other categories, accounting for over 90% of total expenditures each year in the 5-year budget projections[42]. The demand response programs highlighted in this report can offer both long term reductions in usage during peak hours as well as instantaneous response to peak pricing events.

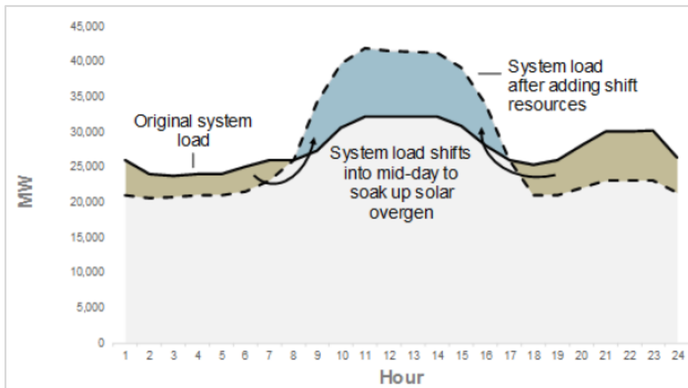

Figure 17: Figure 18: Shift DR moves load into midday hours[1]

Tariff based programs, in particular those with TOU based pricing, offer customers an incentive to permanently shift load away from higher cost procurement times. Many of the other device based programs (including highlighted examples such as EV-to-grid or smart thermostat programs) offer instantaneous response to high load signals from the grid. The combination of encouraging long term load shifting and having ready to deploy DR resources will reduce the need to purchase energy when spot market prices are highest.

As seen previously in this report, current system load peaks in the East Bay occur in the afternoon, and peak pricing events normally land on summer afternoons coinciding with high temperature events. The potential of "shift" type DR can aid in moving peak load away from these peak energy times and toward midday hours when solar generation is high:

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[41] From page 6 of the 2016 report. Reports for the last 10 years available at http://www.cpuc.ca.gov/RA/

[42] From SCP's 2016 Implementation Plan, page 33.

CONCLUSION

Demand response programs can play a foundational role of the energy policy of EBCE by reducing operating costs, providing important resources for reliability, helping to defer upgrades to generation, transmission and distribution systems, and delivering economic benefits both to customers and to the CCA.

Section 1of this report introduced the need for DR by highlighting the load profile across Alameda County and the mismatch in times of peak load and generation. Demand response can play a role by both reducing peak demand and shifting demand to times of favorable energy pricing.

Section 2 of this report, *Demand Response Services and Technology*, highlighted the various types of demand response services that will have the most value in Alameda County along with the technologies that can most aptly participate. Many providers of this technology are local to the Bay Area.

DR is an inherently local product, requiring participation from EBCE customers and involving deployment of technologies at facilities within Alameda County. Section 3 of this report, *Target Customer Base*, highlighted many of the customers who would benefit most from DR programs. This includes many of the largest power users in the County.

As shown in Section 4, *Programmatic Approaches*, there is an effective pathway to enter the DR market incrementally. Initially, EBCE can act as a pass-through entity for existing DR offerings from PG&E. This would allow EBCE to have a DR product available soon after launch while gradually building up the in-house capabilities to eventually have a robust set of programs for customers. Initial DR offerings could lean on the experience of established DR providers, while eventually developing the capabilities to offer DR products and programs directly to customers. Initial years of operational data will inform the optimal DR portfolio, targeting the time periods and customer base that will maximize energy savings.

Finally, Section 5, *Revenue Opportunities for EBCE*, shows there are multiple pathways for a DR program to provide an economic return to EBCE. CAISO's energy and ancillary services markets offer revenue opportunities in the wholesale market. Additionally, DR programs can play a critical role in reducing energy procurement costs and resource adequacy capacity requirements for EBCE. Providing 5% of the total resource adequacy requirement with DR programs would reduce capacity contract costs by upwards of $1.8M/yr starting in 2018. Energy procurement savings will be driven by EBCE's resource mix, with DR offering cost reductions by shaping and shifting load profiles to match up favorably with times of high generation and low cost.

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About Optony

Optony Inc. is a global research and consulting services firm focused on enabling government and commercial organizations to bridge the gap between clean energy goals and real-world results. Optony's core services offer a systematic approach to planning, implementing, and managing commercial and utility-grade renewable power systems, while simultaneously navigating the dramatic and rapid changes in the solar industry; from emerging technologies and system designs to government incentives and private/public financing options. Leveraging our independence, domain expertise and unique market position, our clients are empowered to make informed decisions that reduce risk, optimize operations, and deliver the greatest long-term return on their solar investments. Based in Silicon Valley, Optony has offices in Santa Clara, Chicago, and Beijing.

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