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Case Study of Demand Response in California: Barriers, Policies and Business Models

Working Paper

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Abstract

California has set ambitious climate goals and promotes demand response as part of the pathway towards an environmentally sustainable electric grid. It has one of the highest quantities of enrolled demand response in the country thus lending itself as an ideal case study on the subject. Demand response can provide energy, capacity and ancillary services but there are barriers associated with each of these business opportunities. In this context, we propose a barrier-solution framework in which we list the set of barriers a demand response business can encounter. The barriers are related to existence of markets, profitability and accessibility of markets to demand response products. We present the minimum set of barriers from this framework which must be solved for a business to be viable. We then discuss the drivers of demand response – federal and state policies, financial enablers, and technological enablers – and assess them with respect to the barrier-solution framework, noting the barriers addressed by each driver. Following this, we utilize interviews with demand response providers to propose two business models for demand response – residential aggregation and commercial aggregation – based on the type of customer demand being aggregated. We note features of these models as well as the barriers they overcome. We verify that these business models, in addition to the drivers of demand response, overcome the minimum set of barriers. We end with a discussion on the policy challenges to demand response in California and the policy implications from the case study to introducing demand response into new markets.

List of Abbreviations

AC	Air Conditioning
AMI	Advanced Metering Infrastructure
AS	Ancillary Services
C&I	Commercial & Industrial
CAISO	California Independent System Operator
CCA	Community Choice Aggregator
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
DER	Distributed Energy Resource
DR	Demand Response
ESP	Energy Service Provider
ISO	Independent System Operator
kW	kilowatt
LSE	Load Serving Entity
PG&E	Pacific Gas & Electric
PJM	Pennsylvania, New Jersey and Maryland
PPA	Power Purchase Agreement
RA	Resource Adequacy
RTO	Regional Transmission Organization
RTP	Real Time Pricing
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
TOU	Time-of-Use

1 Introduction:

California has been a climate leader throughout the world. It has set aggressive goals to decarbonize its electricity with Senate Bill (SB) 100 requiring 100% of the state's electricity to come from renewable energy by 2045 [1]. The California Independent System Operator (CAISO) envisions demand response (DR) becoming an integral, dependable and predictable resource that supports a reliable, environmentally sustainable electric power system [2].

California has one of the highest quantities of enrolled DR in the United States. The state's Distribution Resources Plan and Integrated Distributed Energy Resources proceedings require utilities to "identify optimal locations for the deployment of distributed resources." It defines distributed energy resources as distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies. California utilities contributed to 8% of total reported enrolled capacity nationwide, with most of the capacity enrolled through air conditioning (AC) switch, thermostat, behavioral, and commercial and industrial (C&I) programs [3]. All of these make California an ideal case study for DR.

The DR capacity in California is about 2200 MW. The total capacity in the state is about 47,600 MW [4]. Thus, DR capacity is about 4.6% of the total capacity. This is still quite small and shows a potential for growth in the state.

In this paper, we perform a case study of DR in California using our proposed barrier-solution framework. We assess policies, enabling environment and businesses against this framework. We also identify two general business models for DR and propose the minimum set of barriers that must be overcome for a business to be viable.

The remaining sections are organized as follows: we start with an overview of DR touching upon the technology required for DR, the types of DR and the business opportunities and barriers associated with DR. Then, we propose our barrier-solution framework as it relates to the topics outlined in the overview. We also recommend the minimum set of barriers to be addressed before a DR business can become successful. With this framework, we dive into the case study of California, assessing policies and enabling environment based on the framework. Then, we propose two business models and make note of the barriers they address. Finally, we discuss policy challenges going forward and implications of this case study for policy makers outside California.

2 Overview of DR:

The United States Department of Energy defines DR as "an electricity tariff or program established to motivate changes in electric use by end-use customers, designed to induce lower electricity use typically at times of high market prices or when grid reliability is jeopardized." Advances in smart grid enabling technologies has facilitated the growth of DR. This includes information and communications technology, intelligent energy management systems (EMS) and advanced metering infrastructure (AMI).

2.1 DR Enabling Technologies:

2.1.1 Metering and control infrastructure

Smart meters and AMI are crucial for implementing DR. Smart meters are electronic meters which are capable of bidirectional communication between the end-use customer and the load serving entity (LSE). Smart meters can receive signals from the LSE to reduce loads or receive dynamic price signals. AMI refers to a large network of smart meters [5] and is particularly essential for residential DR, which aggregates multiple small loads.

Another technology important in enabling DR is an EMS. This allows for more effective participation in DR programs by allowing automated load response whether it is a residential load or a commercial/industrial load. The EMS can receive signals from both controllable and non-controllable loads including the state of the load and its power consumption. The US is the leader in EMS across the world [6].

2.1.1 Communication infrastructure

For a DR program to be successful and reliable, large amounts of data transfer need to occur. Thus, communication infrastructure is required to enable this. An example of this could be a moderate bandwidth communication path between LSEs and EMS. The infrastructure should not have significant delays to allow for timely responses [6].

2. 2 Classification of DR:

DR programs can be either incentive-based or price-based. In the incentive-based scenario, customers are compensated for altering their load during predefined DR events. In the price-based scenario, loads respond voluntarily to changes in electricity pricing.

2.2.1 Incentive based DR

2.2.1.1 Direct load control:

This type of program typically involves a large number of small customers wherein the utility directly controls specific appliances. These tend to be AC, lighting, water heating and pool pumps [7]. The number of DR events as well as their duration is fixed beforehand. The end-user is compensated in any of the following ways: (1) electricity bill discounts or benefits and (2) payments for being called on. Direct load control events are usually triggered by economic or reliability events.

2.2.1.2 Curtailable load:

These programs are directed towards medium and large-sized customers. Participants are compensated for reducing their load upon being called to by the utility. In these programs too, the number and duration of DR events is predefined. In additions, customers may face penalties for failing to respond. Load curtailments can also be traded in some markets [8].

2.2.1.3 Demand side bidding, capacity and ancillary services:

In this type of program, customers actively participate in electricity markets by bidding demand reductions. Large customers can participate directly while smaller customers may participate through a third-party aggregator [9]. Customers can also participate in capacity and ancillary services markets where applicable [10].

2.2.2 Price-based DR

2.2.2.1 Time-of-use tariffs:

As compared to flat prices, time-of-use (TOU) pricing better reflects the differing costs of serving load at different times of the day. A typical TOU rate structure includes an on-peak rate and an off-peak rate. It may include other periods such as mid-peak and super-off-peak. Customers can schedule their loads to take advantage of lower off-peak prices where possible. This could have the effect of shifting load away from when the grid is the most strained.

2.2.2.2 Critical peak pricing:

While TOU pricing captures the average costs of serving load at different times of the day, it does not incorporate short-term variations. In the event of unexpected strain on the electric grid, utilities may impose critical peak pricing (CPP) which is a high electricity rate that does not depend upon the time of day. Utilities may have a maximum number and duration of such CPP events. Customers can adjust their loads when such an event occurs, thus reducing the strain on the grid.

2.2.2.3 Real time pricing:

A real time pricing (RTP) rate structure is a more complex TOU structure in which electricity rates are updated very frequently and can change from day to day and hour to hour. This type of rate structure better corresponds to the locational marginal price of electricity. Customers responding to this type of price signal can effectively shift or reduce their load when it is most required by the local distribution system. Some studies have shown that RTP is more economically efficient than a flat tariff [11].

2.3 Business opportunities and barriers to DR:

DR can offer multiple value propositions. However, each value proposition has barriers associated with it [12]. These value propositions and associated barriers are listed below:

2.3.1 Energy services

DR can participate in energy markets by offering peak shaving, load shifting and energy arbitrage. This reduces the need for expensive peaking units by flattening the load profile.

Barriers: Data and experience from real-life DR programs is required to increase deployment of these programs. Lack of this information can create uncertainty that will reduce investment potential.

2.3.2 Capacity services

DR can provide capacity and thus participate in capacity markets. Ultimately, it could provide resource adequacy and alleviate some the need for investment in new generation.

Barriers: Although DR provides significant potential for capacity, absence of capacity markets or payments can inhibit the tapping of this potential. Moreover, even when there are capacity markets, there is significant uncertainty around the future of these markets. This poses a challenge for investors in DR.

2.3.3 Ancillary services

DR can provide ancillary services (AS) such as spinning reserves and regulation services. These are becoming increasingly important as the penetration of renewables on the grid increases [13].

Barriers: The rules for participation in AS markets are numerous and complex. This inhibits participation of DR in AS markets and reduces the number of revenue streams for a DR product.

In addition to the barriers listed above, deployment of DR faces behavioral and informational barriers. If consumers do not engage with DR programs, the benefits of DR cannot be experienced, and revenues cannot be realized. Moreover, since load reduction is measured relative to a baseline, the calculation of a baseline is crucial in determining the true value of DR. Imperfect baselines can lead to improper valuation of DR and can be an impediment to further deployment of DR.

3 Barrier-solution framework:

In the context of the barriers and business opportunities outlined in section 2.3 , we propose a barrier-solution framework to assess the role of policies as well as businesses in furthering DR deployment. There are three main barriers and further subdivisions under each barrier. Using this framework, we present the minimum set of barriers to be overcome for a successful DR business.

The first barrier relates to demand in terms of the existence of markets for DR. The absence of demand or the uncertainty in the existence of demand can impede investments into the industry [14]. We distinguish between short-term demand (1-3 years) and long-term demand (5-10 years) within this barrier.

B1: Absence of sizable markets
- B1.1: Lack of short-term (1-3 years) market signal
- B1.2: Lack of long-term (5-10 years) market signal

The second barrier relates to the profitability of the business. This is important to ensure that the industry can sustain itself and there are incentives for new parties to enter the industry and facilitate its growth. Within this barrier, we look at the possibility of one or more revenue streams to cover the capital operating costs. DR is not a capital-intensive business since it requires customer intervention to reduce their existing load.

B2: Lack of profitability

B2.1: High operating costs with respect to main revenue stream

B2.2: Lack of multiple revenue streams to recover operating costs

The third barrier relates to the accessibility to the market. Accessibility includes market and policy mechanisms for DR to participate in energy and other markets, technical standards and protocols for DR participation (such as baseline and test/dispatch requirements) and interconnection processes for DR (such as smart meters and communications technology).

B3: Lack of accessibility to market

B3.1: Lack of market/policy mechanisms or technical standards for DR to participate

B3.2: Lack of interconnection process

From this framework, we propose the following as the minimum set of barriers that need to be addressed for a DR business to be viable.

B1.1 OR B1.2: There must either exist a short-term or a long-term signal to indicate that there is a business opportunity for DR.

B2.1 OR B2.1: There must exist one or more revenue streams that can cover the operating costs of the business for it to be viable.

B3.1 AND B3.2: Not only must there be market mechanisms for DR to participate in energy and capacity markets, there must also be appropriate interconnection processes in place.

4 The Case for California:

4.1 Policy and Enabling Environment in California:

A discussion of policies that enable DR deployment as well as the enabling environment in California is an essential part of this case study. Figure 1 presents a timeline of key policy interventions both at the federal and the state level.

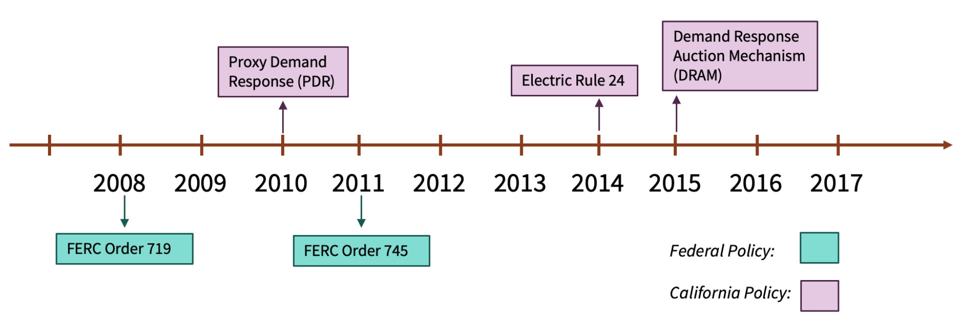

Figure 1. Timeline of key federal and state policies for DR in California

4.1.1 Federal policies:

4.1.1.1 FERC Order 719 (2008):

This order requires regional transmission operators (RTOs) and independent system operators (ISOs) to amend their market rules as necessary to permit an aggregated retail customer to bid DR on behalf of retail customers directly into the RTO or ISO organized markets on behalf of retail customers, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate. This order has had the greatest implications for ISOs that did not have a direct bid-in option for DR. At the time, CAISO already allowed Participating Load, a DR resource, to bid directly into their organized markets but only the large California Department of Water Resources pump load could meet the requirements [15] [16].

Barriers Addressed:

B3.1: This order provides guidance to connect with wholesale markets for DR in regions where this did not previously exist.

4.1.1.2 FERC Order 745 (2011):

This order requires that demand response providers (DRPs) are compensated at market prices when they participate in wholesale markets. It went to the Supreme Court when some generating units filed a lawsuit against the order. However, it was passed by the Supreme Court in 2016 thereby increasing certainty in markets where DR was on hold. ISO New England, in particular, held off on its DR programs till the order was passed in the Supreme Court. This has order led to an increase in DR products. Reliability Demand Response Resource is an example of one such product in California. It is a wholesale DR product allowing emergency responsive demand response resources to integrate into the ISO market [17] [18] [19] [20].

Barriers Addressed:

B1.1: This order provides more short-term certainty in DR markets which has encouraged investment (ISO New England).
B2.1/2.2: It also ensures that DR is compensated fairly which allows revenue coming from wholesale markets to better cover capital costs.

4.1.2 State policies:

4.1.2.1 Proxy Demand Response (2010):

Proposed and implemented by CAISO, this allows DR to bid into ISO markets (day-ahead and 5-min real time energy markets and day-ahead and real-time non-spinning and spinning reserve markets) as supply. Proxy demand response (PDR) requires a minimum load curtailment of 0.1 MW (0.5 MW) for day-ahead and real-time energy (day-ahead and real-time energy spinning and non-spinning reserve). However, smaller loads can be aggregated [21] [22] [23].

Barriers Addressed:

B2.1/2.2: The Supply Side Pilot conducted by PG&E came about after this policy was implemented. It offers capacity payments to supplement market revenues and ensure better capital cost recovery for DRPs.
B3.1: PDR has created defined market mechanisms for DR to participate in energy/AS markets in California.

4.1.2.2 Rule 24 (2014):

This rule, also known as Electric Rule 24 in PG&E and SCE or Rule 32 in SDG&E, allows third-party DRPs to solicit customers to participate in DR programs and bid into wholesale electricity markets. It thus specifies the roles and responsibilities of different entities involved in facilitating direct participation DR such as the utilities and DRPs or aggregators. The rule requires DRPs to enter into a service agreement with utilities and specifies meter data access requirements. It provides consumer protection by instituting protocols for DRP registration at the California Public Utilities Commission (CPUC) and complaint resolution and enforcement [24] [25].

Barriers Addressed:

B3.1: This rule has created a mechanism for participation of customers in DR markets through aggregators. It also specifies protocols for meter data access and consumer protection.

4.1.2.3 Demand Resource Auction Mechanism (2015):

The Demand Resource Auction Mechanism (DRAM) is an open bidding process that allows IOUs to secure enough DR to meet their resource adequacy (RA) needs. The auction is pay-as-you-bid and has been running since 2016. Every year, the auction has expanded in size and services it allows in the market. The upper bound on price has decreased over the years from 443.79 $/kW in 2016 to 165.44 $/kW in 2017 and 113.09 $/kW in 2019. Third party DR in California came about in 2016 due to DRAM [26] [27] [28].

Barriers Addressed:

B1.1: DRAM has created a short-term demand for DR for the duration of the pilot. It has been able to engage new DRPs as well as new customers. 67% of the winning companies between 2016 and 2019 had not previously participated in any IOU DR programs. Between 74% and 95% of customers taking part in DRAM in 2016 and 2017 had not participated in an IOU DR program previously.

B2.1/2.2: DRAM has created a platform for DR to make enough money to cover costs in a reliable manner. The pay-as-you-bid format has ensured that companies are able to recover their costs. The price caps during each year of the auction have given an indication of how much money could be earned in capacity payments.

B3.1: Through the pilot, testing and dispatch requirements have been gradually increased to make DR more reliable. This included issues such as minimum dispatch requirements and qualifying capacity dispute resolution. [29] [30]

4.1.3 Financial Enablers:

4.1.3.1 Time-of-Use Pricing:

As detailed in section 2.2.2.1, TOU pricing is a rate structure where rates vary according to time of day, season and type of day (weekday or weekend/holiday). Higher rates occur during peak demand hours and lower rates during off-peak demand hours. This provides price signals to electricity users to shift energy use from peak hours to off-peak hour. Commercial, industrial and agricultural customers in California are required to be on a time-of-use rate plan while residential customers can opt into a time-of-use rate [31].

Barriers addressed:

B2.1/2.2: TOU pricing provides a revenue stream by creating a value proposition for DR.

4.1.3.2 Demand charge:

A demand charge is a $/kW charge based on peak customer demand which occurs in addition to the volumetric $/kWh rate for electricity consumed. This charge mostly applies to commercial, industrial and agricultural customers. DR can lower demand charges by decreasing customer peak [32].

Barriers addressed:

B2.1/2.2: Demand charges provide a revenue stream by creating a value proposition for DR. PG&E conducted and Excess Supply DR Pilot (XSP) to test the capabilities of demand-side resources to increase load as a service to the grid during the times of excess supply on transmission and/or distribution lines. Multiple participants demonstrated their ability to avoid incremental demand charges and could potentially reduce their demand charges by shifting their load appropriately. This supplemented the capacity payments received as a part of the program [33].

4.1.3.3 Resource adequacy:

The CPUC adopted a RA policy framework (Public Utilities Code section 380) in 2004 to in order to ensure the reliability of electricity supply. RA obligations apply to all LSEs within the CPUC's jurisdiction, including IOUs, energy service providers (ESPs), and community choice aggregators (CCAs). The RA program guides resource procurement and promotes infrastructure investment by requiring that LSEs procure capacity so that capacity is available to the CAISO when and where needed. The CPUC's RA program contains three distinct requirements: system RA requirements, local RA requirements and flexible RA requirements [34].

Barriers addressed:

B2.2: Capacity payments for RA are a strong incentive for DR to enter the market and supplement energy market revenues for businesses to recover their costs [35].

4.1.4 Technological enablers:

4.1.4.1 Smart meters:

Smart meters are necessary to project baseline electricity consumption and compute demand reductions to correctly value DR. The CPUC authorized Southern California Edison (SCE) to install approximately 5.3 million new smart meters, San Diego Gas and Electric Company (SDG&E) 1.4 million electric smart meters and Pacific Gas and Electric Company (PG&E) approximately 5 million electric meters. This is the highest number of smart meters in any single state in the US. All the major IOUs offer TOU pricing for customers with smart meters. Time-based rates are available to PG&E's residential, agricultural, and commercial and industrial customers with a smart meter. SCE customers with smart meters can participate in time-based rates. SDG&E offers time-based rates for commercial and industrial customers as well as the option for residential customers with smart meters. [36] [37] [38]

Barriers addressed:

B3.2: Smart meters allow for measurement of demand which in turn is used for baseline prediction. This allows customers to participate in DR programs.

4.1.4.2 Smart appliances:

Smart appliances allow for automated control of certain devices such as turning them off to reduce demand. Common smart appliances, particularly for residential DR, are smart thermostats and smart plugs. Smart thermostats can control temperature within certain limits to adjust demand (e.g. Nest). Smart plugs can switch on/off devices that are connected to them and can be controlled remotely. They can be quite impactful depending on which device is connected to the plug [38].

Barriers addressed:

B3.2: Smart appliances aid in the interconnection process by allowing for automated participation of customers in DR programs.

Table 1 summarizes the barriers addressed by the policy, financial and technological drivers described above.

Table 1. Summary of barriers addressed by policy drivers and enabling environment.

Driver	Type	Barriers Addressed
FERC Order 719	Federal policy	B3.1
FERC Order 745	Federal policy	B1.1, B2.1/2.2
Proxy Demand Response	State policy	B2.1/2.2, B3.1
Rule 24	State policy	B3.1
Demand Response Auction Mechanism	State policy	B1.1, B2.1/2.2, B3.1
Time-of-Use Pricing	Financial enabler	B2.1/B2.2
Demand Charges	Financial enabler	B2.1/B2.2
Resource Adequacy	Financial enabler	B2.2

Smart Meters	Technological enabler	B3.2
Smart Appliances	Technological enabler	B3.2

5 Business models:

Through informational interviews with DRPs in the industry, we have distilled businesses into two models in California.

1. Model 1: Residential aggregation
   A third-party aggregator company solicits residential customers and aggregates their load to participate in energy or capacity markets.
2. Model 2: C&I aggregation
   A third-party aggregator company solicits C&I customers and aggregates their load to participate in energy or capacity markets.

For each business model, we list the following details:

1. Service type: DR-focused or DR-enhanced
   DR-focused businesses offer DR as their primary product. DR-enhanced businesses offer DR in addition to a primary product (for example, storage).
2. Aggregation type: Residential or C&I
   Aggregation type refers to the type of customers aggregated by the business.
3. Revenue streams: Energy, capacity and/or ancillary service payments
   Information about revenue streams indicates the markets the business participates in and thereby earns revenues from.
4. Drivers: Policies and enabling environment
   Drivers are the federal and state policies as well as the financial and technological enablers which make the business viable.
5. Barriers addressed: Which barriers are addressed and how
   These are the barriers from the framework proposed in section 3, which are addressed specifically by the business model. We would like to note that some barriers are addressed by policies and enabling environment to make it possible for the businesses to exist.

5.1 Model 1 - Residential aggregation:

In this model, load is aggregated from residential customers and controlled using mostly smart thermostats and smart plugs. There are two main sources of revenue - capacity payments and energy market revenues. In California, the capacity payments come from DRAM or RA contracts with a CCA. Energy market revenues are received from both day-ahead and 5- and 15-minute real-time markets. Most of the revenue (~90%) comes from capacity payments but some companies make greater use of the energy market revenues than others. Smaller sources of revenue include research grants, sale of devices, partnerships with device manufacturers and revenues from the ancillary services market. Companies keep ~30% of market payments and pass on ~70% to customers. An example of such a model is OhmConnect [38]. Residential aggregation is particularly prevalent in California due to extensive AMI.

This business model addresses barriers B2.1/2.2 and B3.2. It utilizes multiple revenue streams to recover its operating costs. It also aids in the interconnection of residential customers to DR markets by providing the technology required for them to participate in these markets. Table 2 summarizes business model 1 for residential aggregation.

Table 2. Summary of business model 1 for residential aggregation

Service type	DR-focused
Aggregation type	Residential
Revenue streams	Capacity payments through DRAM/RA contracts and energy market revenues
Drivers	Rule 24, DRAM, TOU rates, RA requirements, smart meters and appliances
Barriers addressed	B2.1/2.2 and B3.2

5.2 Model 2 - C&I aggregation:

In this model, load is aggregated from C&I customers. These loads tend to be larger than residential loads. The two main sources of revenue in California are capacity payments and energy market revenues. Again, most of the revenue comes from capacity payments (about 90%). The aggregator retains a percentage of the revenues and passes the rest on to the customer. C&I customers tend to receive lump sum payments so capacity payments are an important revenue source. Contracts between the DRP and customer are usually 2-3 years long but can also be shorter (1 year). The short length of the contract is both due to low cost of capital as well as the nature of the DRAM pilot where capacity is only required to be locked in a year in advance [39] [40]. C&I aggregation constitutes most (80-90%) of DR capacity. An example of such a model is EnelX.

Before entering a new market, Enel X assesses the total addressable market, attainable market size, program growth potential, pricing forecasts, commercial & industrial share of total customer load, system load shape, and regulatory market certainty among many other factors. For Enel X to make the decision to enter the market, the anticipated margin in the market needs to support the fixed and variable costs associated with running a DR program. These costs vary based on the market requirements. Costs include Enel X personnel costs, metering and controls costs, technology and software development costs, customer acquisition costs (sales) and credit requirements. Enel X also considers other factors in addition to financial viability such as strategic value, future opportunity, value-stacking potential, existing customer base and first-mover advantage. Thus, this business model addresses barriers B2.1/2.2 and B3.2. It utilizes multiple revenue streams to recover its operating costs. It also aids in the interconnection of C&I customers to DR markets by providing the technology required for them to participate in these markets. Table 3 summarizes business model 2 for C&I aggregation.

Table 3. Summary of business model 2 for C&I aggregation

Service type	DR-focused
Aggregation type	C&I
Revenue streams	Capacity payments through DRAM/RA contracts and energy market revenues
Drivers	Rule 24, DRAM, TOU rates, demand charges, RA requirements, smart meters and appliances
Barriers addressed	B2.1/2.2 and B3.2

From section 3, the minimum set of barriers to be addressed for a viable DR business is:

(B1.1 OR B1.2) AND (B2.1 OR B2.2) AND (B3.1 AND B3.2)

Table 4 summarizes how the above business models satisfy this criterion.

Table 4. Barriers addresses in the case of each business model.

Business Model	**Drivers**	**Barriers Addressed**
Residential aggregation	Rule 24, DRAM, TOU rates, RA requirements, smart meters and appliances	B1.1: Addressed by DRAM B2.1/2.2: Addressed by business model B3.1: Addressed by Rule 24 B3.2: Addressed by smart meters/appliances as well as business model
C&I aggregation	Rule 24, DRAM, TOU rates, demand charges, RA requirements, smart meters and appliances	B1.1: Addressed by DRAM B2.1/2.2: Addressed by business model B3.1: Addressed by Rule 24 B3.2: Addressed by smart meters/appliances as well as business model

6 Policy challenges to DR in California:

There are several policy challenges to furthering the deployment of DR in California. They are detailed below. We have summarized these from several informational interviews with various DRPs [38] [39] [40].

B1: Absence of sizeable markets:

B1.1: Lack of short-term (1-3 years) market signal
B1.2: Lack of long-term (5-10 years) visibility of the market

Challenges:

1. The DRAM has been extended for another 4 years but the budget remains capped. This is a conflicting short-term market signal. On the one hand, there is a market for DR for the short-term. On the other, capping the budget suggests that the market will not expand.
2. There is a proposal to cap DR at 5.3% of LSEs total RA portfolio. This is quite close to current market penetration and indicates a lack in long-term market signal. [41]
3. Unlike CAISO, PJM locks in capacity contracts three years before they are due to be delivered. Rules surrounding DR do not change as often as they do within the DRAM. This provides a transparent and clear short-term signal. A similar approach would be beneficial in California. Multi-year contracts are more valuable to capacity providers than single-year contracts at the same price because they take away much of the investment risk.

B2: Lack of profitability:

B2.1: High capital costs with respect to main revenue stream

B2.2: Lack of multiple revenue streams to overcome high capital costs

Challenges:

1. Payments in DRAM are often not high enough to justify making investments. There is no clearing price and bidders in DRAM get exactly what they bid. Thus, they often operate with minimal profit margin.
2. Extensive analyses like Load Impact Protocols are required to determine qualifying capacity in RA markets. These are cost-prohibitive (they cost over $200,000) and can pose a barrier to entry.
3. Risk underwriting is a barrier to DR because short contracts don't ensure revenue. However, shorter contracts are becoming more common primarily because LSEs are only required to secure capacity for a year in advance.

B3: Lack of accessibility to market:

B3.1: Lack of market/policy mechanisms for DR to participate

B3.2: Lack of interconnection process (smart meter)

Challenges:

1. Participation in DRAM is a "logistical nightmare". The DRAM evaluation conducted by the CPUC took some feedback on this in order to plan for subsequent auction rounds.
2. There is no clear standard for baseline computation due to daily and seasonal variations in load.
3. There is uncertainty around how to calculate qualifying capacity and whether the average performance or the best performance with respect to the baseline should be considered. Ideally, DR would replace peaker plants and the average performance method doesn't incentivize this.
4. There is uncertainty around the test requirements for DR. A test involves DR self-scheduling with no market revenues just to prove performance ability. Prior to 2017/18, no tests were required. Now, these tests events must occur in at least half the months in the contract to show that the qualifying capacity can be dispatched.

7 Conclusions and Policy Implications:

We performed a case study of DR in California in the context of the barrier-solution framework proposed in section 3 . Each policy, DR enabler and business model was assessed for the barriers it addressed. The minimum set of barriers that must be overcome before a DR business can be viable were proposed as follows.

B1.1 OR B1.2: There must either exist a short-term or a long-term signal to indicate that there is a business opportunity for DR.

B2.1 OR B2.1: There must exist one or more revenue streams that can cover the operating costs of the business for it to be viable

B3.1 AND B3.2: Not only must there be market mechanisms for DR to participate in energy and capacity markets, there must also be appropriate interconnection processes in place.

The two business models identified, along with policy drivers and enabling environment, overcame the aforementioned minimum set of barriers. They provide us with policy implications for regions in which DR is being introduced. Regions with load growth and congestion have potential for DR by providing short or long-term signals for DR business viability. Capacity payments as well as time-based electricity rates are a strong incentive for DR businesses as they provide streams of revenue to recover the costs of operating the business. Regions that want to promote DR must ensure that there are policies in place to facilitate the participation of DR in the market (energy, capacity and/or ancillary services markets). In addition to this, AMI is crucial to measure demand continuously and calculate baseline demand which in turn is required to measure DR. Thus, smart meters should be promoted to the customer classes in which DR is to be implemented.

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Appendix A

This section contains details from the interview with OhmConnect (OC).

General comments on DR:
DR affects lower impact peaks. Thus far, it hasn't incentivized shifting load to the middle of the day. OC does residential aggregation. SDG&E and PG&E have petitioned for real-time pricing which could incentivize load shifting.

Question: Which policies are key to DR in California? How can we value DR as a RA resource (to determine if there is a market for it)?

Answer: Before 2016, all DR was from IOUs. They would be the aggregators and bid into the market. Third party DR in CA only really started in 2016 due to DRAM. OC came about because of DRAM. IOUs would acquire capacity from DR through a competitive auction. Rules were relaxed to ensure participation. They would be tightened subsequently. Right now, there is a conversation about tightening the rules. DRAM was like an incubator. Now DRAM participants are going out into other RA markets. Real world rules are tighter than the pilot rules. 'Rules' refers to the measures to ensure that participants deliver the capacity they promise. In DRAM, it used to be a take-my-word-for-it approach although, this year, rules are stricter - you have to receive a capacity value from the CPUC calculated based on historical performance. Outside DRAM (where DRPs are acting as aggregators and bidding into RA markets or signing capacity contracts) the qualifying capacity, as it is called, is calculated in Load Impact Protocols.

To summarize, there are 3 ways to declare qualifying capacity:

1. Just by stating it
2. Calculating it based on historical data
3. By performing extensive analysis

Extensive analyses like Load Impact Protocols are cost-prohibitive (cost over $200,000) and can pose a barrier to entry.

Question: Is DRAM becoming bigger?

Answer: DRAM still exists and just got extended for 4 more years. However, the budget has been frozen at 2019 levels. This has been done because: (a) this is just a pilot so there's only so much money the CPUC is willing to spend on this and (b) DR capacity has been expensive thus far so this could hopefully exert downward pressure on prices.

Question: What are policy challenges to DR?

How do you quantify qualifying capacity?
Should one consider the average performance with respect to the baseline or the best performance with respect to the baseline? Best performance is more important because peak days are what is important for DR. The Load Impact Protocol looks at 1-in-2 weather conditions. Ideally, DR replaces peaker plants and the average performance method doesn't incentivize this. In DRAM, qualifying capacity is based on peak performance.

How do you baseline?
There are many methodologies to do this, especially for residential loads (due to weather and seasonal variations).

What should test requirements for DR be?
Before 2017/18, no tests were required. A test involves DR self-scheduling with no market revenues just to prove performance ability. Now, these tests events must occur in at least half the months in the contract to show that you can dispatch the qualifying capacity (QC). To measure QC, you always look at the reduction in load. This is measured as a difference between the demand forecast (baseline) and the measured load (in a DR event, this will be less than the demand forecast). This difference must be the QC. When DRPs sign a bilateral contract with an IOU/CCA, the test requirements are more stringent but only one test event is required because of the stricter requirements.

An aside: in DRAM, capacity is bought by IOUs whereas, outside DRAM, capacity is bought by any LSE. Most RA is bilaterally procured and not really traded on the market.

Should there be dispatch requirements?
Without dispatch requirements, DR could bid very high into the energy markets so as to avoid getting dispatched and simply retain the capacity payments.

Question: Does DR shift demand? Does it do so efficiently?

Answer: In OC's experience, during a DR event, many residential measures decrease load by turning it off. However, some of this load has to be attended to at some point (such as laundry and dishes). Most people just shift this load to right outside the event window. This is referred to as 'bounce-back'. People don't see broader price trends and don't necessarily know when the load should be shifted to so that it's good for the grid. In the ideal scenario, real-time pricing (RTP) reflects the best time, from the grid's perspective, to shift load to. Automation could be a way for people to internalize that. TOU rates are a step in between flat rates and real-time pricing. There is talk of having a voluntary opt-in to real-time pricing like rates. RTP would need technology and automation so that consumers would not have to check rates periodically. OC remotely controls devices and appliances (through smart plugs and thermostats as of now) but it will become necessary to move beyond this.

Question: What are business models that we see being used? What is OC's business model? How does OC make money?

Answer: OC has two main sources of revenue: capacity payments from DRAM or RA contracts with a CCA and energy market revenues from both day-ahead and 5 and 15 minute real-time markets. Residential customers of OC earn only when they dispatch and thus receive payments from this revenue source.

These are the biggest revenues, but other sources include: research grants, sale of devices and partnerships with device manufacturers but this is small compared to capacity and energy market revenues. Initially, most of the revenue (more than 90%) came from capacity payments. Now it's closer to 50-50 between capacity and energy revenues.

Question: What are the technologies used by OC?

Answer: Right now, the technologies used are:

1. Smart thermostats which connect to the OC platform. Eg: Nest
2. Smart plugs - can be quite impactful depending on what is connected.

Higher impacts are seen when the customer is at home when the automated load shut-off event occurs. This way, they notice it and can turn off other devices which are not connected to the platform.

Question: What is the customer acquisition process?

Answer: Ads, mail and billboards but mostly referrals. Some customers already have the devices (smart plugs and thermostats). Others can buy them after they join the program. OC resells Google Nest and other devices. All devices are Wi-Fi controlled.

Question: What kind of customer contracts does OC have?

Answer: Customers get paid by event and performance. There is no lump sum payment. The more you save, the more you are paid. OC gives a demand forecast which is the baseline. OC deducts points if you go above the baseline and if you don't perform when you're supposed to. Points can be cashed in after a certain threshold. DRAM mostly has 1-year contracts. Even outside of DRAM, 1-year contracts are the most common. This is because LSEs only need to show capacity for a year ahead.

Question: Where in California are the customers?

Answer: OC is active across California and has contracts with all 3 IOUs. Number of contracts in PG&E > SCE > SDG&E. OC is headquartered in the bay area. There are about 150,000-160,000 OC customers in CAISO. This is a small percentage of total customers. OC doesn't participate in the ancillary services market.

Question: Does OC do project level finance?

Answer: Yes, they do to calculate bid prices. They have a target $/MWh. OC wasn't profitable at the beginning.

Question: What's the incentive for DRPs going out into RA markets? Why are utilities picking them over traditional generators?

Answer: DR is not the cheapest resource. There is a premium on DR as there is on all clean energy sources. For CCAs, it's the clean/green aspect of DR that makes it appealing. Unsure how DR compares to wind and solar, but it is seemingly comparable since DR is securing contracts.

Question: What is the discussion around real-time pricing so far? Is it going to be a voluntary program?

Answer: Real-time pricing (RTP) has been discussed at the CEC in its Load Management Rulemaking. They have talked about adding RTP to the tariff. It's the CPUC that actually develops the tariff. CEC will ask utilities to provide one RTP tariff by 2022. It will be a general mandate and it is uncertain how this will go. PG&E and SDG&E have rate cases open to make adjustments to pricing. OC is submitting a proposal to PG&E. It looks like it will be an opt-in program for all types of customers.

Question: What are the business models that we see?

Answer: OC is the only big residential aggregator. OC makes the most use of the energy markets. Other companies rely on capacity payments. C&I customers tend to have lump sum payments so capacity payments are more important.

Question: How much DR is there in the market? Is there greater potential?

Answer: Refer to the CPUC state of the market report for DR breakdowns. August is discussed as it is the month with the highest demand. There is about 290 MW of DR, most of it through DRAM, while about 50-70 MW are credited to CCAs. Overall, there is about 2000 MW of DR in CA. This is still a small percentage of total capacity in CA. Residential programs tend to be smaller. The total available market for DR depends on the Maximum Cumulative Capacity for RA. This prevents an LSE from buying only one type of resource and becoming too dependent on it. Right now, DR is unrestricted to promote more DR. However, there is some concern that there is too much reliance on DR.

Appendix B

This section contains details from the interview with Autogrid.

Question: Where are major DR markets? What drives them? Implications for India: What are the barriers and how can they be addressed?

Answer: DR can offer capacity and ancillary services. Major markets are New England, PJM, New York, California, Northwest, MISO (for emergency and load-following DR) and Florida. Regions where there are forward looking policies or utilities are good markets for DR. Outside the US, Europe has mostly deregulated electricity markets. In the APAC region, Vietnam, Thailand, Australia, Japan and Hong Kong could also be good markets. Regions that have load growth and congestion have potential for DR. In North America, the west and east coasts have the biggest markets. Eg: ERCOT, CAISO, PJM, NY, ISO-NE

Question: Where do revenues come from?

Answer: The utility may pay DRPs or payments may come from the wholesale market. In PJM, there is the Base Residual Auction. Markets where the $/kW-yr is high provide good revenue for DR.

Question: In California, what are different ways to participate in DR?

Answer: On the regulated side, richest payments from the utility are from contracts with DRPs. E.g.: SCE, CBP from PG&E

Most Autogrid clients mix and match DR with DER. CCAs and local municipalities are catching up and adding DR in their portfolios. Big aggregators in California are: CPower, Direct Energy, NRG, THG (real estate). You can find the DRP contracts on the IOU websites.

On the deregulated side, there are some market mechanisms which allow participation.

1. DRAM: 220 MW of resource adequacy. From a policy perspective, there are barriers to participation.
2. SSP (Supply Side Pilot) program: PG&E
3. EIM (Energy Imbalance Market): There has been a lot of talk about this market. DR may be looking to participate.

Question: What are revenue sources? Why are you in the business? What are the business common models?

Answer: Business models are quite varied.

1. Traditional aggregator: (E.g.: EnerNOC) Mostly C&I customer aggregation. Offer aggregated capacity in the market. Keep 30% of market payments and pass on 70% to customers. Usually have a 2-3-year contract but there has been a tendency to have shorter term contracts (1 year). Year-round participation is starting to be required which is harder. This requires more flexible and innovative contracts. This creates a secondary market where there is a reverse auction for another party to take on the risk. For example, aggregator A takes a position in the PG&E auction

by bidding 10 MW but only has 8 MW. They would then call other aggregators to make up for the 2 MW and sell it off.

2. Non-traditional models: Non-traditional players are trying to enter the market (with DER capacity). E.g.: Tesla, SolarCity, Sunrun. They already have hardware (like charging points) and can use this to participate in DR. They can then offer cheaper rates to customers.

Customer incentives and customer acquisition are the biggest drivers of DR.

Question: How do you do project finance for such short contracts?

Answer: Risk underwriting is a barrier to DR and DRAM because short contracts don't ensure revenue. On the contrary, ITC + SGIP see 5-7-year long contracts for storage. But it makes sense because there is hesitation around committing to long contracts when prices are falling so much.

In India, PPAs are getting shorter (1-year long contracts). Flexibility would offer price hedging.

Question: What are the barriers to DR in CA?

Answer: Participation in DRAM is a "logistical nightmare". The scheduling coordinator, DRP and customer all have to interact, and the process is not straightforward. The bidding process is archaic and not very automated. It is designed to handle scheduling of ~5 big generators and not many small DRPs. The portal requires re-registration every time capacity goes slightly below 100 kW and this is not automated. There is a waiting period for the utility to confirm the bid.

Question: What are other barriers?

Answer:

1. Lack of knowledge on how much money one can earn since DRAM is a blind auction. Aggregators have a hard time knowing how much to expect. DRAM never discloses what they clear at. The auction is pay-as-you-bid. If you win in the auction, you participate in the energy market.
2. Baseline computation: California uses a 10-of-10 approach. Unclear policies about how storage to be calculated.
3. Payments are not high enough to justify making investments.

Question: How can these barriers be overcome?

Answer: There could be a simpler process although this could lead to baseline gaming. The simpler process could look like: where are the MW required and how much are you willing to pay?

Question: What are DR markets that are working well?

Answer: Every market has challenges at the moment since all markets are designed with traditional generators in mind. E.g.: ISO-NE didn't allow residential aggregation until recently.

Question: Where is the action in India?

Answer: AG has conducted pilots in several villages close to Tirupathi. They automated farm control based on soil moisture content. Incentivized farmers to run farms at off-peak hours. The automation was app-based. The contract was with the farmers and the AP distribution company such that farmers got a free app to control their farms remotely. The farmers biggest concern was snake bites at night and not water/electricity consumption. To the distribution company, this was kind of a proof of concept to show that they could shift the load to off-peak hours which is highly beneficial. This would result in savings to the distribution company. This wasn't a shared savings contract, just a pilot contract.

AG is also looking into residential AC programs as well as commercial programs. The residential program involves providing smart ACs (free or cheap) or smart plugs. Right now, this is also in AP although they would like to move to other states.

Question: How do you ensure reliability of DR?

Answer: DRAM has test events where you have to prove that you have the capacity that you said you would. There are steep penalties if you don't perform (no capacity payment and you are exposed to the wholesale market). There is the possibility of gaming the system by bidding very high in the energy market, so you don't have to perform.

Appendix C

This section contains details from the interview with Tesla.

Question: How does Tesla participate in DR in California? DRAM? Any other avenues?

Answer: The California DRAM is relaxed. Tesla is active in DRAM and has been receiving capacity payments. However, DRAM is not sophisticated. Tesla has two very active projects - Green Mountain (peak load reduction in ISO-NE, which comes with high performance requirements) and the South Australia VPP (Virtual Power Plant). In Australia, the VPP acts as a full retailer, offering a fixed rate to customers and using optimization algorithms to bid into wholesale markets. In comparison, the California DRAM is much more low-tech, and requirements are minimal. The capacity payments are definitely a strong incentive to enter the market. However, you only have to clear the wholesale energy market every once in a while, which is easy.

Question: How do you make money off of DR? Who are the clients?

Answer: Cutting out the supply chain (for example, a retailer that is different from the plant owner) helps cover costs efficiently. South Australia is the market to be in for VPP as the market is ripe with opportunities for a number of reasons:

1. The government is interested in renewables.
2. The economic dispatch model is linear and not a mixed integer optimization which makes it faster to solve.
3. The grid is 'thin' which leads to high volatility in prices; when there is a fault prices can and do get very high allowing for arbitrage.

Compared to this, California's market design is 5-10 years behind. 'Good' policy design allows for multiple players being able to add value. Environments that are market driven, i.e. where there is direct exposure to price volatility, make VPPs profitable.

Question: What are business models seen?

Answer: For VPPs, every project is different. It is important to have the right players/partners. Green Mountain Power has been a good partner. They provide customers with back-up power in the form of batteries. When the batteries are not being used, they can interact with the market. Tesla provides the technology (batteries). So here, there is customer demand as well as some exposure to market prices. ISO-NE also has good incentives for batteries.

Question: What are policy challenges to DR?

Answer: The unit commitment model takes a while to solve. It would be beneficial to pass down market exposure to resources that can respond instantly. DRAM is designed for big C&I resources that simply turn on/off. This is not the optimal program for fast resources like batteries. In South Australian energy markets, you can bid 2 minutes before dispatch. On the other hand, in California, feedback on when you get an award and how much is slower. The more real-time the better. Californian markets and the DRAM is currently set up for less sophisticated players. The

DRAM only allows participants to bid into spinning reserves AS markets and the day-ahead energy market, which are easy to do.

In South Australia, they have frequency controlled ancillary services which operate in time scales of seconds. CAISO needs to open up frequency control to DRAM assets. There are additional questions on how a VPP should provide a frequency signal and whether an AGC is the best way to regulate frequency. The South Australian markets are way ahead in terms of market design. The prices in California are not volatile enough for VPPs.

Appendix D

This section contains details from a series of interviews with EnelX.

Question: How does EnelX participate in demand response in California? Is it mostly through DRAM?

Answer: I think DRAM is currently the most common DR program we participate in California. Base Interruptible Program is another program that our customers participate in. See https://www.enelx.com/n-a/en/resources/data-sheets-brochures/california-demand-response-guidelines for more information.

Question: Who are the customers and what is the customer acquisition process?

Answer: Customers are large commercial and industrial facilities from a variety of subsegments. Customer acquisition appears to involve a fair amount of inside-sales (calling or emailing potential customers), as well as putting out marketing material to demonstrate our expertise and attract leads.

Question: What are the revenue streams for commercial and industrial demand response? How do businesses make money and how do they pass on these benefits to their customers?

Answer: Enel X typically receives capacity and energy payments from the utility or grid operator, based on fleet-level nomination and performance. This payment is then passed along to customers (commercial/industrial facilities), with Enel X keeping a portion.

Question: What barriers have been faced with regards to increasing demand response deployment in the state?

Answer: At the moment, it seems that there's a lot of regulatory and market uncertainty around DR in California. This is particularly true of DRAM, which is technically still a pilot.

Question: What fraction of your capacity participates in DRAM vs. BIP (approximately)? I'm wondering which of the two programs has increased the quantity of demand response deployed.

Answer: I'm not sure of the exact split, but BIP is an old utility emergency DR program and is effectively capped to further growth.

Question: Is revenue skewed towards capacity payments?

Answer: Yes, the vast majority of revenue typically comes from capacity payments for the CA DR programs I'm aware of.

Question: What are the major regulatory/market uncertainties or barriers in California right now? Are there other markets where EnelX participates that seem to have overcome these?

Answer: There are a number of short-term barriers or uncertainties that are largely program-specific. Enel X participates in a number of other markets, each of which sees its own regulatory ups and downs. Our regulatory and government affairs teams help us stay up to date with regulatory changes and helps advocate for more a favorable DR market.

Question: Are you starting to see participation outside of these pilots or programs (like DRAM or BIP) just directly into resource adequacy contracts with like CCAs or smaller utilities in the state?

Answer: In general, if I understand correctly, existing demand response constructs are often times one of the only available vehicles for these behind the meter demand side resources to provide resource adequacy which in some cases create some perverse incentives. For instance, it may be undesirable to shift load from midday to evening on non-event days if your performance is measured relative to what you would do on those nonevent days. This becomes particularly relevant for resources like storage that are capable of being dispatched every single day whereas historically demand response was intended for sale large commercial customers or industrial customers that are shutting down their load very infrequently in response to a notification.

Question: Are their significant hardware costs for your company? That might decide whether long-term contracts are important or not.

Answer: We install metering because among other things that would allow us to see during an event how customers are performing and provide feedback during the event to let them know that they're doing well or that they need to curtail load more etc. Metering and telemetry is a capital expense but I don't think it is a particularly high cost. Contracts may also come from the fact that the utility or the aggregator has bid and won a certain amount of capacity with CAISO and are expected to provide a reliable level of curtailment over some time period. Signing a contract with those customers helps ensure that customers that are willing to participate for an extended period time and willing to commit to that.

Question: What are major market/regulatory barriers.

Answer: There might be barriers that are relevant for particular resources participating in demand response but not for others. For instance, if we had a solar plus storage project for a customer which is sized large enough to export to the grid during events we would not receive compensation for doing that. If demand response is considered a load modifying resource then the possibility that you could be exporting during events is not considered. One of the justifications is that somehow it's compensated through net metering in a very indirect way. This prevents this type of DR from achieving its full potential. Many other barriers exist in this vein.

Question: For solar+storage programs, do customers already have the hardware?

Answer: In our case, we're installing new DERs on their premises and then also serving as the demand response aggregator and providing access to value streams. There are companies out there that are figuring out ways to take existing assets and offering those customers the ability to participate in wholesale markets and receive extra payments through them. That seems to be a relatively recent development in part because there weren't that many of those resources out there until relatively recently.

Question: What is the business model used by EnelX? How does the business make money?

Answer: EnelX is a demand response aggregator. We bid into an auction of some kind and agree to provide a certain amount of demand response capacity and take on that and we would the responsibility for that capacity. It is then our responsibility to go out to say commercial industrial customers in a particular area and doing all that outreach, marketing and sales effort and finding those customers, recruiting them and seeing what sorts of loads they might have that could be curtailed during events. We would install the metering and telemetry equipment that we talked about before as part of the pre-sales process. Once the customer is signed up, we would be responsible for ensuring that our portfolio of customers performs and meets whatever we've committed to with the utility. We could send customers an email before the event with a reminder and even send them an email during the event letting them know in real time whether they are a meeting the performance target that they agreed to. After we have been paid for our performance, we pass the appropriate split of payment that we've received onto those customers for their performance. That's the basic business model for a demand response aggregator. We're offering access into these value streams that are challenging to access by virtue of our market knowledge.

Question: What are the incentives for the utility versus incentives for the customers?

Answer: In California, the utility or grid operators are required to procure demand side resources as first priority to the extent that they can. Calling upon an aggregated or non-aggregated demand response resources is oftentimes cheaper and cleaner than calling upon a peaker plant in a time of great stress.

Question: Do you perform analyses of the potential of DR in different states before entering the market?

Answer: Consulting firms or other research organizations may write DR potential reports for utilities or public utilities commissions. This would tell states how much DR to procure as a part of their generation portfolio. They may do this in the form of an auction or a tariff.

Question: From a business perspective, you need to have a sense of how large the market is before you get into it. How are you getting a sense of this? One the one hand, programs like DRAM tell you how much capacity they are looking for. What other signals do you use to figure this out? Market refers to (1) upstream: amount DR capacity to be sold to utility or system operator and (2) downstream: how much capacity can you get customers for. How did EnerNOC decide to enter California or any other state? What was the decision-making process? How do you even decide whether the opportunity is worth pursuing?

Answer: It's probably just based on experience in existing markets and existing programs. In California there have been changes to which programs are available. The program that existed before DRAM gave a sense of how much DR was available in the state.

Question: It sounds like DRAM is the main signal in California. Would you say that's right?

Answer: I believe that appears to be one of the main one of the main vehicles in California. Other programs in the state are BIP and the capacity bidding program.

Question: Are there any other variations that you've seen around the US? Why is your focus on C&I as opposed to residential customers?

Answer: Demand response historically was pretty much exclusively commercial and industrial because the original demand response was basically that the utility or the grid operator would pick up the phone and call the biggest customers in their service territory and ask them if they could shut down in response to a payment. It's far easier to call a you know an aluminum smelter than it is to call a 100,000 households. Only recently with companies like OhmConnect and others has the residential DR market really started to open up.

Question: What percentage of DR is C&I?

Answer: I think it's still pretty commercial dominated. OhmConnect is still only operational in California. Residential DR is still a relatively new thing although it is growing quickly particularly with smart thermostats and other smart devices.

Question: Is the major incentive for the C&I customer just a reduction in demand charges? Why are they participating in the program?

Answer: They would receive a capacity payment through us and an energy payment for their performance. It's separate from reducing their own bill (through demand charges).

Question: What are other large DR markets in the US or elsewhere (outside CA)?

Answer: PJM has been the largest market for EnerNOC and is true especially now. The east coast markets are simply more lucrative than California right now.

Question: What is the typical procurement of DR in PJM? Is it market based in that you just go to the market or are their more targeted programs?

Answer: I would guess that we are participating in PJM's capacity market.

Question: Which one is more profitable: demand flexibility or grid services?

Answer: Demand response is a pretty established business. Storage is more of an emerging market and a growth opportunity for us while DR is more of our bread and butter. There are interactions between the two. We're leveraging our DR knowledge to become a leader on the storage side of things.

Question: To operate in CA/PJM/ERCOT what's a comfortable market size when you are planning ahead? 3/5/7 years out?

Answer: Auction oriented mechanisms look a couple of years out. Agreements with utilities are a couple of years long.

Question: How do you measure profitability? (PJM vs CA)

Answer: Capacity payments and to a lesser extent the energy payments in PJM are higher. Cost of doing business the same in both places.

Question: To operate in any jurisdiction, from a project finance perspective, what kind of returns are you looking for in a business like this?

Answer: We take a split of the savings with the customer. That's probably enough to cover whatever acquisition costs are in addition to the risk associated with participating this sort of thing.

Question: What are the administrative issues in California in terns of interconnection to grid or transaction cost related issue?. What are issues remaining and what has been addressed well by California?

Answer: For traditional demand response not involving storage there is really no interconnection required. In that regard, the administrative costs of making a project happen is much lower so the associated project time is much lower. It is largely the market uncertainty that is one of the primary barriers in California. DRAM is a pilot and so we can't necessarily count on having that as a revenue stream if there's a chance that it may not exist in a few years.

Question: What is the planning horizon while scoping out a new market to enter? What kind of market size (in terms of DR capacity) are you looking for and how many years out do you need to plan for?

Answer: Enel X does not typically enter new markets where we don't expect to be either the #1 or #2 DR provider. We also conduct analysis on total addressable market based on market sizing analysis to ensure there is a meaningful opportunity. New market entry can fall into three main categories: a greenfield (new) DR market, an existing market whose rules have changed to become more attractive, or utility-run DR programs where Enel X can be awarded a direct contract with the distribution utility. Regulatory efforts to open a new market to DR can take years. For example, Enel X has been advocating to open an Australian National Electricity Market (NEM) wholesale market to DR since 2012, and just this past July the Australian Energy Market Commission (AEMC) announced a draft rule to open the market starting in 2022 (over 10 years). However, smaller-scale DR programs negotiated directly with distribution utilities can move quite quickly with supportive regulators and the right utility incentives. The Ameren Missouri utility-run DR program went from an opened regulatory proceeding to an approved program and Enel-X-won RFP within 18 months.

Example reasons why Enel X would not participate in a market (or participation is limited):

- Load participation is specifically disallowed.
- Load participation is not technically disallowed, but no DR framework (e.g. no market role for aggregators, no baseline methodology defined, no remuneration scheme for DR).
- Unattractive market
    - France has a very well-designed capacity market and sensible program rules for DR. However, there is no shortage of capacity in France (due to existing nuclear fleet), so there is not much need for capacity DR. And there are already several major DR players (existing high competition), so we would be very late to the party.
    - Partly because of heavily subscribed interruptible tariffs (alternatives to wholesale DR) and partly because of low capacity pricing, MISO has historically been a relatively-unattractive market.

- Significant barriers
    - Delivery: It's important that delivery is not too far ahead that customers cannot commit, but far enough that aggregators can find customers and build a portfolio. The PJM approach of a three-year forward capacity market works well. Also, multi-year contracts are more valuable to capacity providers than single-year contracts at the same price, because they take away much of the investment risk. The UK capacity market makes multi-year contracts available to generation, but discriminates against DR by offering only 1-year DR contracts. Most markets offer non-discriminatory single contract durations, except ISO-New England (offers up to 7 years, but does not discriminate based on technology) and PJM.
    - Customer access: Enel X operates as an independent aggregator, which is crucial for enabling smaller loads to participate. Prior to 2017, there was only one demand resource providing frequency control ancillary services (FCAS) in the Australian National Electricity Market (NEM). Although the market rules allowed for aggregation and for any size of customer to participate, customers' suppliers had to offer them into the market. After a rule change in 2017 that allowed independent aggregators to operate without contracting with the customers' supplier, demand-side participation rose to be 14% of the FCAS market. There is a similar problem in Germany, which requires direct contracts between customer retailers and aggregators to sort out imbalances from DR dispatches. Restricted access to customers is a huge market barrier, and competition can only occur if aggregators can operate separately from suppliers/retailers.

Question: What kind of hurdle rates (approximately) do you operate with for the DR part of the business? By DR, I mean demand flexibility.

Answer: High-level, Enel X assesses total addressable market, attainable market size, program growth potential, pricing forecasts, commercial & industrial share of total customer load, system load shape, and regulatory market certainty among many other factors when assessing whether to enter a new market. We have proprietary modeling tools to assess new market opportunities. Our anticipated margin in the market needs to at the minimum support the fixed and variable costs associated with running a DR program which will also vary based on the market requirements. These costs include Enel X personnel costs, metering and controls costs, technology and software development costs, customer acquisition costs (sales), credit requirements, etc.

Question: What kind of financial modeling occurs in order to decide whether a project/market is worth pursuing? Is payback period important or is it NPV/profit margins or something else?

Answer: The type of modeling depends heavily on the market and type of initial investment required, and the long-term potential of the opportunity. Enel X also considers other factors in addition to financial viability such as strategic value, future opportunity, value-stacking potential, existing customer base, first-mover advantage, etc. The details of this assessment are proprietary to Enel X's internal strategy and are program specific.

Question: What are the signals that tell you there is demand for DR in a market (both on the customer side and the utility side)?

Answer: There are number of different factors that indicate how much participation there will be in DR. Depending on how different programs score on the following, you can tell how much participation there will be.

Resource availability: If DR is only required for a few critical hours, participation will be better than if it is required throughout the day.

Event trigger: When the event trigger is transparent to the market, participation will be higher than if it is arbitrary.
Advance notice: Advance notice of an event boosts participation as compared to expecting an instantaneous response.

PJM is a good example of a market that performs well on these three factors.

Question: What is PJM doing to make it a better market for DR than California?

Answer: PJM is the most well-designed market for DR. California is on the opposite end of the spectrum as compared to PJM when it comes to resource availability, event triggers and advance notice. The rules and auction dates for DRAM are not fixed in advance. The number of hours DR needs to participate per year is also increasing. In PJM, DR participates in the same capacity market as other resources which puts it on a level playing field as all other generating sources.

For residential DR however, California is paving the way due to extensive AMI. As AMI expands in other states, residential DR might pick up outside California.

Question: Is C&I DR more worthwhile than residential DR? Residential DR seems to require an extensive network of smart meters and it might take time to achieve this in new markets.

Answer: You get more bang for your buck with C&I aggregation since these customers have much higher loads than residential customers. It is also easier to manage fewer large customers. Additionally, C&I customers are more likely to spend more money on electricity and care about reducing this cost. For residential customers, the motivations are entirely different and businesses need to look into influencing behavior and tapping into a customer's desire to live more sustainably. The value proposition is very different.

Question: Is the major incentive for the C&I customer just a reduction in demand charges? Why are they participating in the program?

Answer: Customers get payments for participating in DR programs. In some regions, EnelX also helps customers optimize their load to avoid high demand charges (e.g., Ontario).