EPC-15-074: Meeting Customer and Supply-side Market Needs with Electrical and Thermal Storage, Solar, Energy Efficiency and Integrated Load Management Systems

Task 3: Wholesale Market Integration Report

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Prepared for
California Energy Commission

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Contents

I. Executive Summary

The main objective of this report is to present an overview of wholesale market participation requirements, challenges, and the revenue potential pertaining to two portfolios of distributed energy resource (DER) aggregations for *EPC-15-074: Meeting Customer and Supply-side Market Needs with Electrical and Thermal Storage, Solar, Energy Efficiency and Integrated Load Management Systems (STEEL)*. Each portfolio will provide demand response services to the grid by participating in the California Independent System Operator (CAISO) day-ahead and real-time energy markets.

Portfolio 1 consists of an aggregation of five public school facilities located in Chino Hills, CA. Each school has behind-the-meter solar PV and Tesla Powerpack battery energy storage systems (BESS), with the energy storage being sub-metered for performance evaluation. Portfolio 2 consists of two hotel facilities located in San Diego, CA and uses advanced energy management software developed by Conectric Networks to evaluate whole-premises metered performance. Each Portfolio is to participate in the wholesale market utilizing the CAISO Proxy Demand Resource (PDR).

Section 2 of this report guides the reader through the implementation of a PDR along with addressing key issues and topics surrounding this specific resource type, namely performance and baseline methodology calculations and related developments that have arisen from the CAISO Energy Storage and Distributed Energy Resource (ESDER) initiative. Section 3 introduces the framework for which revenue generating potential of each Portfolio may be assessed, identifying key inputs and considerations along with a series of questions that help guide the process. Additionally, a phasing timeline of all market-based activities (real and simulated) for both portfolios is included. Section 4 presents key industry related challenges impacting behind-the-meter DER'S today. Below is an outline of the types of challenges covered in this report:

- Lack of Revenue/Equality
- Demand Response Modeling
- Baseline and sub-metering
- DER Aggregation Issues

Also included in this report is a variety of graphs, tables and figures to help illustrate key concepts and the relationship among all relevant actors along with a description of key regulatory items affecting DERs today. A primary goal of this report is to connect high-level wholesale market concepts and rules to that of the respective Portfolios. This report should not be taken as an operations guide on how to integrate resources into the markets, but rather as a first of a series of wholesale market reporting deliverables under *EPC GFO-15-074: STEEL.* In summary, the key takeaways in this report include the following:

- Timeline requirements and associated costs for enrolling a DER into the market are in dire need of streamlining if we are to keep pace with the continued acceleration of DER growth. This is especially important in instances when a resource can provide ancillary services to the grid.

- ESDER illustrates the importance of stakeholder input in furthering the advancement of demand response as an asset to the grid. Continued outreach and inclusion by CAISO is critical towards this endeavor.
- Much work remains to bridge the knowledge gap between non-market actors – i.e., the general public, business community, and advocacy groups – and the CAISO. Third-party aggregators and service providers can play a viable role in this effort.

II. Demand Response Participation Options

Two Portfolios of distributed energy resources (DERs) have been selected to demonstrate the revenue generating potential and challenges surrounding wholesale demand response (DR) today. Portfolio 1 consists of five public school facilities located in Chino Hills, CA, each of which is comprised of solar photovoltaic (PV) and Tesla[1] Powerpack energy storage devices. Portfolio 2 consists of two hotel facilities located in San Diego, CA.

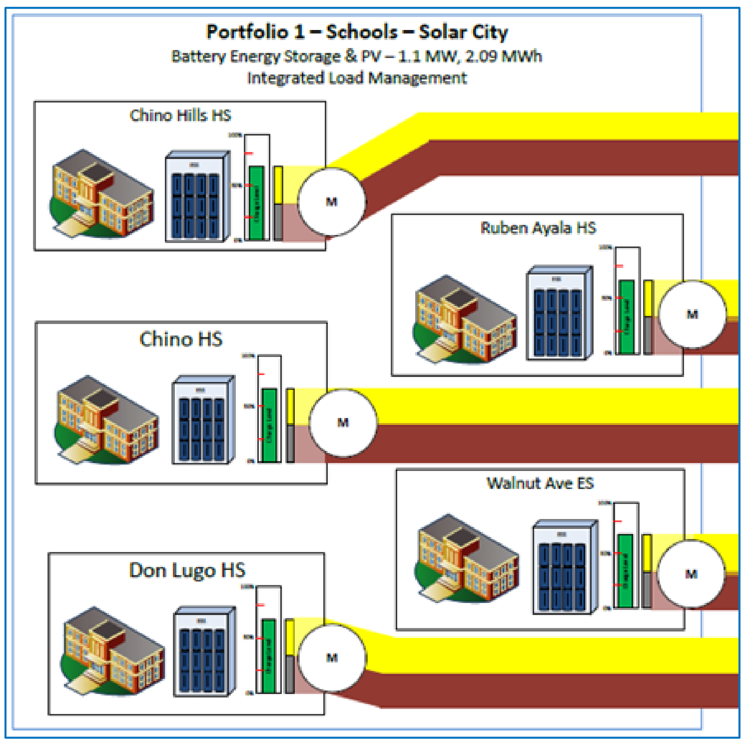

Figure 1: Portfolio 1 Configuration

[1] Note that at project conception in early 2017, SolarCity, Inc. was listed as the project partner. The purchase of SolarCity by Tesla, Inc. in mid-2017 transferred the project responsibilities to Tesla, Inc.

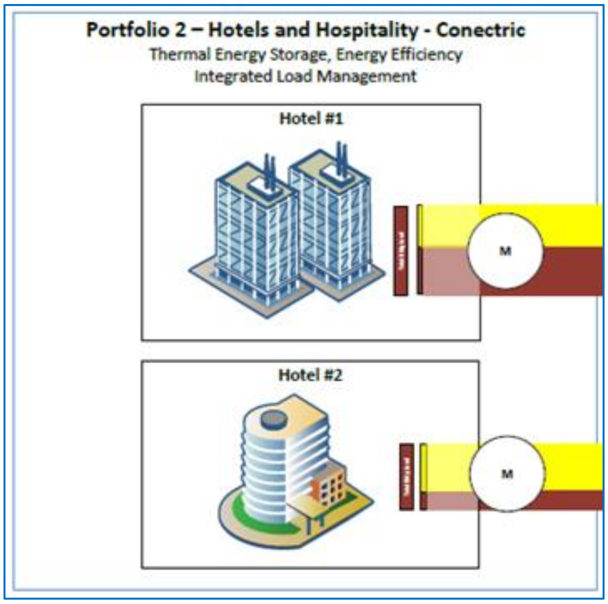

Figure 2: Portfolio 2 Configuration

The next section provides an overview of demand response options for the portfolios, with an emphasis on the CAISO Proxy Demand Resource (PDR) resource type, incorporating relevant requirements and timeline of activities for participation in the wholesale markets.

2.1 Wholesale Market Demand Response

Historically, wholesale market participation was restricted to large, traditional generation plants. Retail customers provided Demand Response (DR) services to the grid via specifically tailored retail electric programs. The Federal Regulatory Energy Commission sought to remedy this by requiring wholesale markets to allow distributed energy resources (DERs) to participate in wholesale markets.

This development led the California Independent System Operator (CAISO) to create models for DERs to participate directly into the wholesale markets. The Proxy Demand Resource (PDR) model is the first and most successful example of such, allowing DERs to aggregate and provide energy and ancillary services to the grid. Under this architecture, demand response can participate at all hours of the day/year and interact with the grid without needing to rely on its Load Serving Entity (LSE). The CAISO also benefits with direct visibility into DR availability, simplifying the forecasting and scheduling process for the CAISO.

To participate in the wholesale market, each PDR must be able to provide a minimum of 100 kW of measurable load curtailment for energy markets. If the PDR will also provide ancillary services, this minimum is raised to 500kW. The customer locations that make up a PDR must be served by a single Load Serving Entity (LSE) and reside inside within a single Sub-Load Aggregation Point (Sub-LAP). Additionally, telemetry with the grid is required for PDRs that are greater than or equal to 10 MW or participate in the ancillary services market.

Additionally, a PDR must be aggregated under a CAISO wholesale demand response provider (DRP) and represented by a certified Scheduling Coordinator (SC). Customers seeking to participate in the wholesale markets cannot be concurrently enrolled in either a retail demand response program or in any other CAISO resource.

All customer segment types can participate as a PDR: residential, small and medium businesses (SMB), and commercial and industrial (C&I) entities. Participation as a PDR allows DERs to create value on both sides of the meter, providing grid stabilization and enhancing market efficiency while allowing for multiple revenue streams to feed directly to the resource owner.

Other models for DER participation in the wholesale markets include the Reliability Demand Response Resource (RDRR) and Non-Generating Resource (NGR) models:

- RDRR follows a similar construct as PDR with the key differences being that resources participating under this model must be able to provide a minimum of 500 kW of measurable load curtailment potential and when bidding into the real-time (RT) market, must submit them as emergency energy bids. RDRR is primarily purposed as emergency responsive DR, does not allow for participation in the ancillary services market, and is deemed unsuitable for this demonstration project.
- Under the NGR model, DERs are primarily suited to be in front of the utility meter (i.e., connected directly to the distribution or transmission grid). This resource type must also meet the 500 kW minimums and unlike the PDR model, can provide regulation up and down services to the grid. NGR is generally seen as an option designed for storage applications and can be challenging to integrate into the wholesale market due to a lengthy and complicated interconnection process. Given the behind-the-meter nature of the portfolios in this project, NGR is not under consideration as a participation model for either Portfolio.

2.1.1 PDR Implementation

Each Portfolio will proceed through a series of stages and market participation activities that make up the full lifecycle of a PDR (seen below). The remainder of this section is dedicated to adding clarity to this process by communicating key elements and market operation requirements, at each stage of the PDR lifecycle.

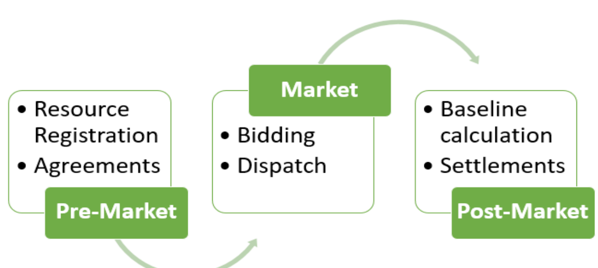

Figure 3: PDR Lifecycle

Before registration at the CAISO, there are several steps that must be completed. Customers will execute a Customer Information Service Request (CISR) to grant Olivine customer data access from the respective investor-owned utility (IOU), as well as an additional participation and data sharing agreement. This agreement grants Olivine, the wholesale certified DRP, permission to register Portfolio locations into the CAISO Demand Response Registration System (DRRS). The terms of these agreements fall under SCE Rule 24 and SDG&E Rule 32 for Portfolios 1 and 2, respectively. The relationship between the relevant actors can be seen in the diagram below.

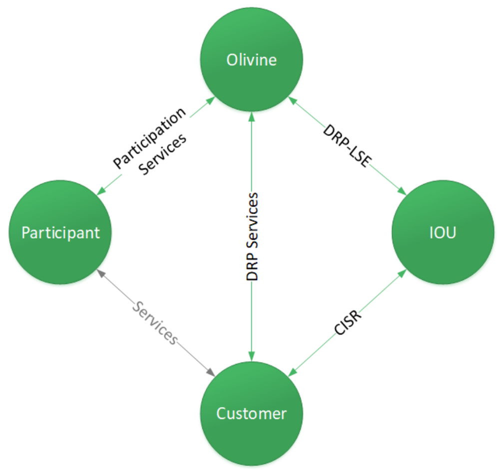

Figure 4: Actor Relationship

Upon securing all necessary agreements, location registration into the DRRS will begin. Primary functions of the DRRS include the registration of locations and resources to ensure no duplication of customers, and managing the validation processes with the UDC and LSE. The DRP registers the locations into the DRRS at which point the UDC and LSE can validate the locations. Examples of required location information includes the UDC account, customer name, address, LSE, and Sub-LAP for each account. Once this data is provided in the DRRS, a validation process commences with the UDC and LSE having an opportunity to validate the customer information.

Once the locations are validated, the DRP may proceed to create resource registrations.[2] Required resource information includes resource type, effective dates, baseline methodology, and whether the PDR will be pre-defined or custom as described below:

[2] Once the locations are validated, the DRP may register an individual location or an aggregation of several locations into a resource.

- Pre-defined Resource: This is a resource that is already modeled in the CAISO full network model and assigned to an aggregated Pricing Node (P-Node).
- Custom Resource: A resource for which the DRP desires a custom distribution of pricing notes. The creation of a custom resource ID requires an addition to the CAISO Full Network Model (FNM) and therefore must follow a much longer registration process than a pre-defined resource.

Both Portfolios will utilize pre-defined resources. For Portfolio 2, there is some interest in analyzing whether a customer resource may provide a better financial outcome. Portfolio 1 will also participate in ancillary services by providing spinning reserve services. As such, Portfolio 1 requires telemetry, falling under a subset of the CAISO FNM New Resource Implementation (NRI) process. Under the NRI, Portfolio 1 will submit required site telemetry information[3] and undergo a sequence of CAISO tests for market readiness. The implementation timeline for the respective Portfolios is seen below.[4]

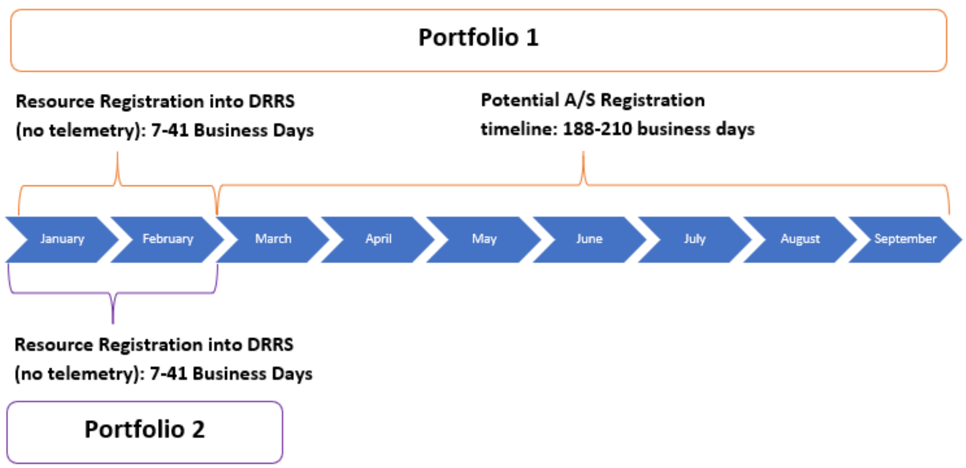

Figure 5: Portfolio Registration Timeline (2018)

One thing to note is that while Portfolio 1 will go through the NRI process, it will be able to bid energy in the shorter timeframe. Once implemented, the portfolios will move into operations. This will include bidding economically into the day ahead and real-time energy markets. Bids are dispatched and awarded for performance of their load curtailment obligations over the course of a specified period of an event day.

[3] Site information includes single-line diagram, three-line drawings and communication block diagram.

[4] Note that CAISO registration for both portfolios will begin at the same time, even though entry into the market will be staggered.

PDRs are compensated for the energy they provide at the Locational Marginal Price (LMP).[5] Ancillary service compensation is driven by market-wide auction. The LMP itself consists of a single energy cost (i.e. the System Marginal Energy Cost), loss factors, and congestion prices, with the latter two being determined from distribution factors applied to the LMPs of the underlying PNodes to which the PDR is modeled. There are no non-performance penalties for PDRs, but there can be consequences for non-performance for ancillary services.[6] Bidding is submitted by the SC into the CAISO Scheduling Infrastructure Business Rules (SIBR) system – a platform utilized by the CAISO to validate and accept bids and make any modifications, if necessary.

The award and dispatch of energy is conducted by the CAISO Customer Market Results Interface (CMRI) and Automated Dispatch System (ADS), respectively. In the event of an energy award, Olivine, the SC, will receive market results, day-ahead energy schedules and A/S award information from the CMRI and proceed to send a notification to the respective Portfolios. During real-time market operations, the CAISO transmits dispatch instructions via the ADS. Transmitted signals may include startup and/or shut-down request along with possible curtailment and ancillary service instructions.

The final aspect of interest in the PDR is the settlement of market-based performance of each Portfolio. This process requires the submission of historical and event performance meter data (at the resource level) in order to true up actual performance of participating resources. The CAISO DRS will download and calculate relevant customer baseline information, evaluating compliance to event dispatch instructions. DR is modeled and awarded equivalent to that of a supply-side resource, whereby "generation" is the measured and verified difference between the baseline load and actual demand, i.e., consumption (note that customer baseline and performance evaluation methodologies are discussed in section 2.1.2.), as seen below in Figure 4.

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[5] LMP = system marginal cost of energy + marginal cost of congestion + marginal cost of losses

[6] See page 7 of Navigant (2012*) Potential Role of Demand Response Resources in Maintaining Grid Stability and Integrating Variable Renewable Energy under California's 33 Percent Renewable Portfolio Standard*, Prepared for the California Measurement Advisory Council (CALMAC). Accessed December 18, 2017 at URL: http://www.calmac.org/publications/7-18-12_Final_White_Paper_on_Use_of_DR_for_Renewable_Energy_Integration.pdf.

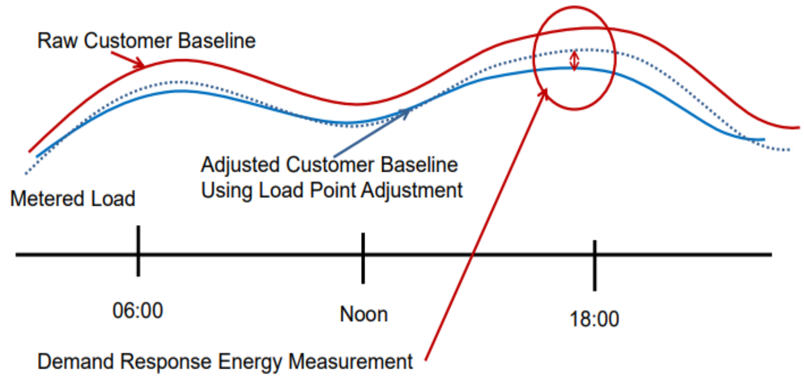

Figure 6: Demand Response Energy Measurement[7]

Additionally, the CAISO will apply necessary adjustments to the performance, depending on which type of performance evaluation method is selected for the respective Portfolios.

2.1.2 Wholesale Grid Services

There are several wholesale grid services that can apply to DERs as described below.

Energy is bid in the day-ahead and real-time markets. Energy requirements are forecasted by the CAISO and while the energy is supplied primarily via bilateral contracts procured outside of the wholesale market, the CAISO ensures that remaining gaps in supply and demand are fulfilled in the energy markets. Energy transactions for both supply-side and demand-side resources operate under the same market rules for bidding. For PDRs, day-ahead bids are due by 10 AM in the preceding day. Day-ahead awards, if any, are published at or around 1 PM in the preceding day. These awards consist of one or more hours. Real-time bids are due 75 minutes before the trade hour, and can result in differing dispatch amounts every 5 minutes. Both portfolios will deliver day-ahead and real-time energy.

PDRs can provide non-spinning and spinning reserves, both ancillary services, to the grid. Non-spinning reserves is a capacity product for resources that can be synchronized and ramped up to the grid within 10-minutes of a dispatch instruction. Spinning reserves are intended to already be synchronized (i.e., on-line) with the grid and can meet the dispatch target within 10-minutes. In practice, there is no difference for PDR resources between these two, except that spinning reserves has an additional frequency response. This frequency response requirement for a PDR is that such a resource must achieve 10% of

[7] See slide 134 of CAISO (2015) "Energy Storage and Aggregated Distributed Energy Resource Education Forum," presented on April 23, 2015. Accessed December 18, 2017 at URL: http://www.caiso.com/Documents/Presentation-EnergyStorageandAggregatedDistributedEnergyResource-EducationalForum.pdf.

its awarded quantity autonomously within 8-seconds when detecting an under-frequency event. Portfolio 1 will deliver spinning reserves as part of the STEEL project. Note that when these capacity products are called on by the CAISO, they convert to operating in the real-time energy markets and compensation mechanism.

Frequency Regulation is an additional ancillary service that will be tested under the STEEL project, although PDRs are not currently eligible to provide this service. Participating resources are synchronized to the grid and capable of providing reserve capacity responsive to a 4-second Automated Generation Control (AGC) signal. This service ensures continuous balance between supply and demand on the grid and operated under the CAISO regulation up and down markets, respectively.

A final service is Resource Adequacy (RA). California LSE's are mandated to procure capacity to meet 115% of their annual system peak load. This mandate ensures that there is always enough capacity to serve load. RA is unique in that it does not generate revenue from the wholesale market; instead, payments for RA come from separate bilateral contracts with LSEs, with the CAISO enforcing requirements on the RA provider. While PDR resources can qualify for RA obligations, the lack of bilateral contracts and the additional CAISO requirements are not well suited to the STEEL project.

2.1.3 Performance & Baseline Methodologies

An important topic for resources participating in the wholesale market is the ability to earn the full value of services provided to the grid. Accurate baseline and performance evaluation methodologies are necessary to enable fair value of these services and to support the continued proliferation of DERs into these same markets. These specific challenges, among others facing DERs today, are addressed in the ongoing ESDER Initiative, currently in its third phase.

ESDER Phases 1 and 2 introduced several enhancements to wholesale demand response participation. Phase 1 established the Metering Generator Output (MGO) model as a performance evaluation methodology, while Phase 2 presented new baseline methodologies. The following section discusses these developments and their applicability to the respective portfolios.

Alternative performance evaluation methodologies (MGO)

Generally, DR performance is computed from whole-premises metering only,[8] utilizing a baseline methodology to determine the counterfactual (i.e., whole-premises behavior if the DR event did not occur). With such meter data, the CAISO is unable to distinguish the specific source of a DR event

[8] Note that the statistical sampling performance methodology also relies on whole premises meter data.

separate from other loads and the potential effects they would have on a particular DR event dispatch. For example, BTM energy storage may provide the intended response while other uncontrolled loads drive performance down. In addition, the charging behavior of such a device may unfairly skew a baseline. Such challenges inhibit the ability to derive a reliable baseline for demand response performance evaluation, resulting in customers unable to capture the full value of their resources.

The CAISO improved this for storage under ESDER Phase 1 with the adoption of the MGO model for PDR and RDRR.[9] MGO is defined as a performance evaluation methodology that computes the performance of a demand response event based upon the output of a sub-metered generator located behind the revenue meter. The MGO model introduces three participation options, each with a specific metering configuration and performance evaluation methodology, depending on which resources (load and/or generation) are registered into the DRRS. MGO is supported by the following scenarios:

- Method B1 (Load Only): Performance (demand reduction) is a result of the output of the whole-premises meter with the sub-metered generation removed.
- Method B2 (Generation only): Performance is a result of the output of the sub-metered generation device (e.g. storage); following the same non-export rules for PDR and RDRR.
- Method B3 (Load and Generation): Combination of the BTM whole-premise metered load and sub-metered generation output.

Portfolio 1 will leverage Method B2. Under this configuration, generation output of the sub-metered Tesla Powerpack system is directly metered for calculating event performance during an event dispatch interval. Note that this configuration still must abide by the PDR net-export rule whereby any negative value (export of energy) registered by the revenue meter during the same interval is automatically subtracted from the BTM generator's discharge value. Under Method B2, a baseline calculation is still applied to determine the counterfactual.

Baseline Methodologies (new and old)

Historically, DR resources have utilized the customer load baseline (CBL) methodology (ISO Type-1), the purpose of which is an attempt to determine the counterfactual condition: what would the behavior have been without the demand response event. This methodology utilizes a "10-in-10" day selection with a window of 45 calendar days from which 10 eligible days are selected of the same day type.

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[9] Note that the former issue supports general sub-metering that could apply across any technology; however, the CAISO provided a solution supportive of energy storage only.

Eligible days include the most recent days within the 45-day lookback window with no demand response performance event occurrence falling on the same day type (i.e., either on a weekday or weekend/holidays[10]). Once the 10 most recent, eligible days are selected, an hourly average of meter data is used to generate a load profile; using a simple average of the similar non-event days. Finally, a day-of adjustment is applied (+/- 20%) to compensate for any unknown variables that might not be visible in meter data. In the case that 10 eligible days cannot be located, there are rules in place to choose fewer days. Ultimately, if the number of days cannot be met, the highest usage prior event days within the same lookback window will be used to generate the baseline.[11]

MGO utilizes the same 10-in-10 non-event day selection and 45-day lookback window method that is applied under the CBL methodology, with the key difference being the absence of a day-of adjustment. Additionally, if the minimum number of eligible days cannot be reached, the baseline will be set to zero (0); charging the storage device does not qualify as an event.

While the CBL methodology may function well for certain customer profiles, it does not adequately serve as a baseline calculation for residential and small commercial businesses, as the load profile for these customer types generally exhibit a less uniform behavior than for instances a large commercial or industrial site. This is primarily attributed to their susceptibility to changes in weather and/or varying local consumption behavior. Additionally, it does a poor job supporting scenarios in which a resource is dispatched frequently nor does it provide the level of accuracy necessary to adequately measure the contributions made by a BTM device.

To help resolve these issues, the CAISO added additional methodologies in ESDER Phase 2 for PDR and RDRR with three distinct baseline methodologies to support a range of demand response baseline methodologies:

- Control Group Methodology: Evaluates the energy consumption of a set of statistically similar, non-participating customers with the energy consumption of the participating customer.
- Weather-Matching Methodology: Evaluates the energy consumption on days with the most similar weather profile to the event day.

[10] Only North American Electric Reliability Council (NERC) designated holdays may apply.

[11] See page 152 of Anderson, Robert W., Sence Gerber, and Elizabeth Reid (2014) "Distributed Energy Resources Integration: Summarizing the Challenges and Barriers," Olivine, Inc. Availabe at https://www.caiso.com/Documents/OlivineReport_DistributedEnergyResourceChallenges_Barriers.pdf.

- Additional Day-Matching Methodologies: Baseline estimates are based upon what electricity use would have been in the absence of a DR dispatch, relying exclusively on the electricity use data from the dispatched customers.

These new baseline methodologies do come with increased complexity for the provider. Primarily, this is due to shifting the burden of computing resource performance from the CAISO to the resource provider. There are also increased data requirements under weather-matching, added complexity of commingling residential and commercial entities under weather-matching methodology, and potential increased cost to enroll customers under the control group methodology; the last challenge, regarding the control group methodology, is largely viewed as barrier for third party service providers – California's IOU's can utilize their respective large pools of non-enrolled customers for a given control group. (And in response, it has been suggested that such profiles be made public for third parties to utilize.) These new baseline methodologies are scheduled to go in effect in October of 2018.

2.2 Retail Demand Response Options

Customers may choose to participate in many retail DR programs offered by California's three IOU's. A challenge facing innovative DR portfolios is that conventional DR programs have a reliance on peak hours. The portfolios in this project will evaluate and determine the value that wholesale demand response can provide outside of conventional IOU DR programs offered today.

Retail DR Programs	Description
Capacity Bidding Program (CBP)	An event-based program offered by all three of California IOUs, operating load curtailment on weekdays between the hours of 11am-7pm. Customers enrolled in this program receive a monthly incentive payment, even if no load curtailment events occur. Participation is through a 3rd-party aggregator (or self-aggregate) with the option to control how much one may bid, per month.
Base Interruptible Program (BIP)	An option for non-residential IOU customers and Aggregators that can provide minimum load curtailment of 100kW or more. Customers that are enrolled must partake in provisions of their respective IOU TOU rate schedules. The IOU will receive a request from the CAISO to reduce electrical load for emergency situations. These events can be called 24-hours a day.
Critical Peak Pricing (CPP)	A summer-oriented program offered to commercial and industrial customers to reduce or shift their energy consumption when demand for energy on the grid is significantly higher than usual. Participating customers are charged a higher rate during peak periods and for their participation benefit from reduced rates during non-peak periods. Peak pricing events operate between 2pm-6pm for PG&E[12] and SCE customers and 11am-6pm for SDG&E customers. Each IOU sets its own maximum number of events that can be called per year; 15 for PG&E, 12 for SCE, and 18 for SDG&E.

Table 1: Retail Demand Response Programs

Demand Response Auction Mechanism (DRAM)

While not a retail program, the Demand Response Auction Mechanism (DRAM) is a utility-driven pilot project initiative aimed at securing supply-side demand response to fulfill system, local, and flexible capacity requirements for Resource Adequacy (RA). The DRAM operates under a pay-as-bid auction whereby awardees aggregate and bid into the CAISO market and must abide by all CAISO rules. All RA procured under the DRAM is subject to the IOU rules governing direct participation (i.e., PG&E and SCE Rule 24, and SDG&E Rule 32).

III. Revenue Generating Opportunities

DERs have the potential to generate multiple revenue streams for the services they provide to the grid. It is generally considered that the majority of behind the meter DERs in CA today consists of customers who are enrolled in "retail" IOU DR tariffs or programs. But additional revenues can come in the form of

[12] Though not a specific DR program, PG&E's peak pricing rate plan operates under the same construct as CPP programs offered by SCE and SDG&E, respectively.

energy, non-spinning, and spinning reserves payments directly from the CAISO. Capturing the full value of providing grid services requires thoughtful planning and evaluation of what resources can deliver – in terms of available load curtailment potential and their responsiveness to wholesale market price signals.

This section details how each portfolio can proceed to generate revenue streams and what questions may arise over the course of preparing for wholesale market participation. We note that this report is not a market operation manual, nor does it provide suggested bidding strategies, but instead establishes a framework for estimating DER revenue potential – as illustrated in this section of the report.

The following questions were designed to help the participants better evaluate participation options in the wholesale market.

What is the available capacity of each Portfolio?

To understand revenue potential, we must start with available capacity: the controllable quantity of load above local consumption needs including the comfort of building occupants. Generally it is not a fixed quantity and each portfolio will have a variable amount of curtailable load to offer. In addition, CAISO rules for PDR require that all delivery of services be non-exporting to the grid. In practice, this may have the impact of reducing available capacity during solar production hours.

What are the historical clearing prices (for energy and A/S)?

When determining the potential revenue streams for wholesale market participation, it is important to consider what prices may be paid for such services. A reasonable place to start is to look at past clearing prices. These prices are accessible via the CAISO Open Access Same-Time Information System (OASIS) Portal.

What is the right price to bid a resource into the market?

Determining the optimal bid price for energy and capacity requires a host of local operational constraints be taken into consideration along with how they connect with market price signals. Local constraints can include startup and commitment cost and if the resource(s) are capable of delivering at a specified hour of the day. Important to note is that bid price does not directly correlate with available capacity; that an inverse relationship exists between the price threshold and quantity of dispatches. Additionally, bids for resources composed of customers that take energy service from an IOU must clear the system Net Benefits Test (NBT); a price set by the ISO determines if a bid is cost effective under current market conditions.

When is the right time of day to bid?

Participation as a PDR or RDRR allows resource owners the opportunity to bid their resources' capacity at all hours of the day, noting that there are certain hours of the day that will prove to be most advantageous to place a bid into the market. For example, bidding during the hours of the 4pm-9pm can qualify for Resource Adequacy and generally do have higher clearing prices than other times of the day. A resource may only seek to bid their capacity at hours of the day that contain a pre-set price threshold in-mind.

These times must likely be aligned with customer needs. In the case of Portfolio 1, the storage assets are primarily purposed to manage retail demand charges and therefore orient their available capacity throughout the day as such. For Portfolio 2, there exists a constant need to balance all market bidding activities with occupancy comfort levels at any given hour of the day.

How to co-optimize demand response with facility bill management?

Creation of revenue-generating demand response strategies depends in large part on the ability to function alongside existing local bill management and occupancy requirements. The goal is to ensure that costs created by wholesale market participation do not impact the primary use case for the assets underlying the portfolio. For example, Portfolio 1 must ensure a harmonious relationship between demand-charge mitigation and wholesale market participation. A potential solution could involve placing bids on days and hours that do not directly correspond with a battery discharge for load-management activity.

What is the desirable frequency of dispatching resources?

Energy revenues are impacted by the frequency of dispatch, which in turn is dependent upon the price threshold for triggering a DR event. Dispatch for energy should take place as often as possible without negatively impacting the primary use case or other customer requirements (e.g., customer occupancy comfort).

IV. Energy

Each Participant will have the opportunity to bid into the day-ahead (DA) and real-time (RT) energy markets. Participants will have the option to set their bid prices as low as possible (i.e. as a "price taker") or to choose a threshold price at which it creates value for the participant; noting that bid prices must be at or above the net-benefits test (NBT) price as defined by the CAISO. Participants are compensated based upon the LMP for a specified time period in which a market bid is cleared and subject to resource performance.

The following tables illustrate the revenue potential of participating in the energy markets. All capacity, duration hours, and quantity of dispatch inputs were provided via the respective project participants Tesla for Portfolio 1 and Conectric for Portfolio 2. The average clearing price figures were derived from CAISO OASIS for the year 2016 using available data for the Sub-LAP in which each portfolio resides.[13]

[13] The SCEC Sub-LAP was used for Portfolio 1; with SDG1 used for Portfolio 2.

Portfolio 1

Potential revenue for DA bidding is derived using each Portfolio's available capacity and their respective pricing strategy. Portfolio 1 follows a price threshold strategy in which the storage assets are only dispatched when the market clears a price that is pre-set by the resource owners.

Month	Available Capacity (kW)	Dispatch Hours	Average Clearing Price ($/MWH)	Potential Revenue ($)
January	800	0	N/A	$0.00
February	800	0	N/A	$0.00
March	800	0	N/A	$0.00
April	800	0	N/A	$0.00
May	800	0	N/A	$0.00
June	800	2	$106.53	$170.45
July	800	2	$104.01	$166.42
August	800	0	N/A	$0.00
September	800	0	N/A	$0.00
October	800	0	N/A	$0.00
November	800	0	N/A	$0.00
December	800	0	N/A	$0.00
			Total Revenue:	**$336.87**

Table 2: Annual Revenue Generating Potential: Day-Ahead Energy (Portfolio 1)

For this portfolio, Tesla has indicated 800 kW of available capacity and 2-hours of discharge potential per day with a $100/MWH price threshold. The average clearing price was derived by filtering for hours in which day-ahead energy prices cleared above $100/MWH in the market for 2016. The resulting prices were then averaged, by month. Only 4 hours across two months exceed this threshold. The potential DA revenue at this price is quite low considering how few hours clear at this price. Noting that 2016 had lower prices than typical, it is not uncommon that only a handful of hours in any year would clear this threshold in the day-ahead energy market. As a result, this strategy fits in better in the real-time market, as illustrated in Table 3 below.

Month	Available Capacity (kW)	# of 5-minute intervals	Average Clearing Price ($/MWH)	Potential Revenue ($)
January	800	24	$547.03	$875.25
February	800	24	$614.60	$983.37
March	800	24	$565.11	$904.18
April	800	24	$461.19	$737.90
May	800	24	$423.36	$677.38
June	800	24	$579.03	$926.44
July	800	24	$531.86	$850.98
August	800	24	$583.41	$933.46
September	800	24	$417.04	$667.26
October	800	24	$545.65	$873.05
November	800	24	$525.73	$841.17
December	800	24	$643.90	$1,030.23
			Total Revenue:	**$10,300.68**

Table 3: Annual Revenue Generating Potential: Real-Time Energy (Portfolio 1)

The same available capacity and discharge potential for DA energy applies for RT market operations. Each dispatch represents a 5-minute interval in the RT market. Additionally, the same methodology for calculating average clearing price ($/MWH) in DA calculations was used, noting that it is common for RT prices to exceed $100/MWH in every month of the year. The potential revenue column reflects this shift from hourly intervals to 5-minute intervals. The average clearing price was derived using the same methodology for day-ahead energy; resulting in a higher potential for Portfolio 1.

Portfolio 2

Portfolio 2 is anticipated to follow a price-taker strategy and as such will be compensated for market prices that have cleared the NBT for each month. Again, the same methodology for deriving the average clearing price is used with the monthly NBT value serving as the price threshold. Both day-ahead and real-time potential revenue is provided in the following tables.

Month	Available Capacity (kW)	Dispatch Hours	Average Clearing Price ($/MWH)	Potential Revenue ($)
January	39	431	$35.80	$601.69
February	42	155	$42.19	$274.65
March	49	89	$35.07	$152.92
April	54	253	$31.14	$425.42
May	59	157	$37.75	$349.63
June	71	384	$44.10	$1,202.23
July	84	258	$51.13	$1,107.98
August	83	212	$51.49	$906.10
September	72	170	$50.00	$612.00
October	64	222	$48.57	$690.06
November	47	103	$50.22	$243.10
December	38	261	$51.04	$506.26
			Total Revenue:	**$7,072.05**

Table 4: Annual Revenue Generating Potential: Day-Ahead Energy (Portfolio 2)

Month	Available Capacity (kW)	# of 5-Minute Intervals	Average Clearing Price ($/MWH)	Potential Revenue ($)
January	39	2404	$61.17	$477.93
February	42	904	$69.95	$221.32
March	49	712	$128.73	$374.25
April	54	1782	$70.36	$564.19
May	59	1088	$58.99	$315.55
June	71	224	$74.60	$98.88
July	84	2166	$87.11	$1,320.80
August	83	1312	$105.32	$955.70
September	72	1201	$98.46	$709.51
October	64	1087	$108.41	$628.49
November	47	903	$159.85	$565.33
December	38	1093	$106.59	$368.91
			Total Revenue:	**$6,600.88**

Table 5: Annual Revenue Generating Potential: Real-Time Energy (Portfolio 2)

Portfolio 2 performs better in the day-ahead market. The resource has more available dispatch hours in the day-ahead versus the real-time market, despite the clearing prices generally exhibiting higher prices than real-time prices. Considering this, it may make sense for Portfolio 2 to participate in the day-ahead market exclusively. Alternatively, they may participate in both markets noting that the day-ahead revenue and the real-time revenue are exclusive and not additive.

Portfolio 2 benefits from a wider range of availability for event dispatch; at all hours of the day in which the price has cleared the NBT. While this strategy appears to provide an interesting revenue opportunity, it is based on a very high number of dispatches which greatly reduces the number of eligible days for baseline calculation. Such a strategy poses interesting policy questions about the use of counterfactual baseline methodologies that would be used to establish the non-event behavior profile.

4.1 Ancillary Services

Portfolio 1 will have the opportunity to participate in the ancillary services market by providing spinning reserves to the grid. Resources providing these services to the grid can bid at all hours of the day and still receive compensation for hours that are bid but not dispatched. The estimated revenue generating potential for providing spinning reserves can be seen below using inputs provided by Tesla and 2016 historical clearing prices for A/S. Table 6 shows the estimated top range of revenue potential from the ancillary services market if the maximum amount of available capacity were dispatched many times for extended periods of time (6 hours). Table 7 shows an estimated low range with less available capacity and fewer dispatches, on-average, for the ancillary services market over the course of a given year.

Month	Available Capacity (kW)	# of Hours/Day	Quantity of Dispatches (per month)	Average Clearing Price ($/MWH)	Potential Revenue ($)
January	800	6	30	$2.69	$387.36
February	800	6	30	$3.76	$541.44
March	800	6	30	$4.56	$656.64
April	800	6	30	$5.39	$776.16
May	800	6	30	$5.85	$842.40
June	800	6	30	$7.00	$1,008.00
July	800	6	30	$9.29	$1,337.76
August	800	6	30	$7.15	$1,029.60
September	800	6	30	$6.04	$869.76
October	800	6	30	$9.14	$1,316.16
November	800	6	30	$7.35	$1,058.40
December	800	6	30	$6.33	$911.52
				Total Revenue:	**$10,735.20**

Table 6: Annual Revenue Generating Potential: Spinning Reserves (Price Taker)

Month	Available Capacity (kW)	# of Hours/Day	Quantity of Dispatches (per month)	Average Clearing Price ($/MWH)	Potential Revenue ($)
January	200	5	30	$10.78	$323.40
February	200	5	30	$8.16	$244.80
March	200	5	30	$10.34	$310.20
April	200	5	30	$10.38	$311.40
May	200	5	30	$8.55	$256.50
June	200	5	30	$10.58	$317.40
July	200	5	30	$12.24	$367.20
August	200	5	30	$9.44	$283.20
September	200	5	30	$6.23	$186.90
October	200	5	30	$5.50	$165.00
November	200	5	30	$7.21	$216.30
December	200	5	30	$5.93	$177.90
				Total Revenue:	**$3,160.20**

Table 7: Annual Revenue Generating Potential: Spinning Reserves (Price Taker-RA Hours Only)

4.2 Phasing Participation

Each Portfolio will demonstrate the wholesale market value opportunities through real and simulated market participation activities. Market interface and simulation activities will be operated from the *Olivine DER®* platform to support bidding, dispatch, real-time telemetry and AGC. The first phases for both portfolios will begin with day-ahead market participation, advancing to real-time participation, with a final phase one goal of combining and maximizing value from both market participation opportunities. Provided below is a timeline for all market activities for the year 2018.

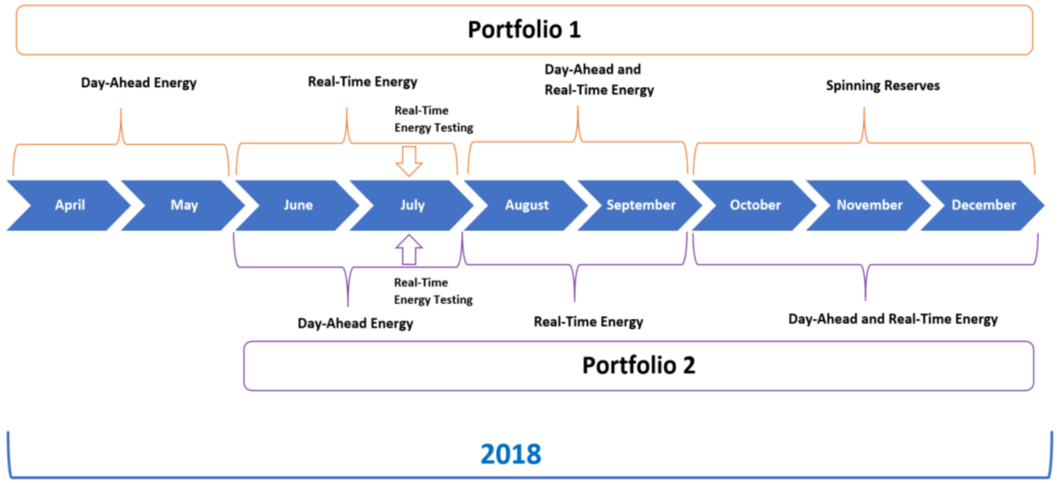

Figure 7: Portfolio Phasing Timeline (2018)

As the project moves into 2019, each portfolio would include frequency regulation simulation and the potential for testing out new CAISO models as defined within ESDER Phase 3, as illustrated below. This could include the simulation of a load-shift product; though we note that the ESDER Phase 3 items for consideration and market implementation are not yet determined or fully defined. All activities will test and evaluate market functionality for the respective portfolios and their responsiveness to wholesale market price signals.

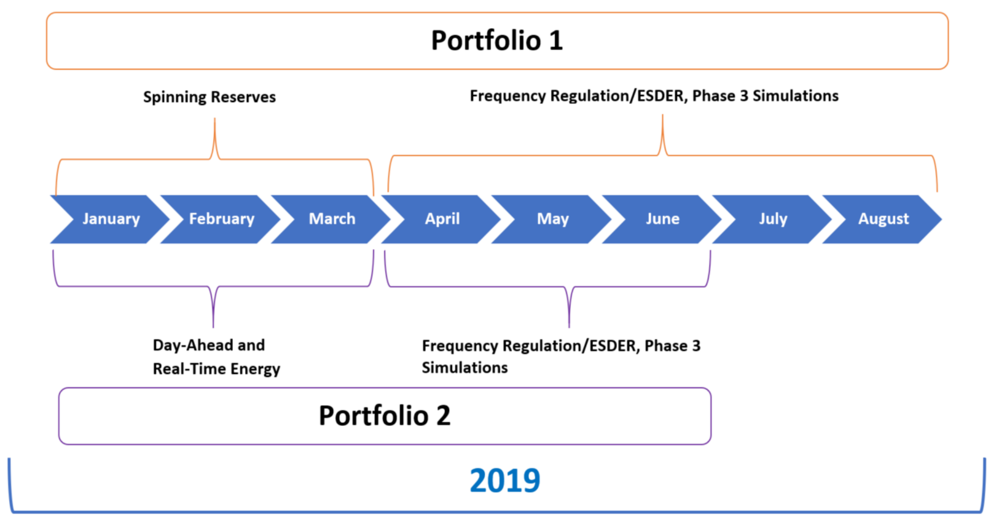

Figure 8: Portfolio Phasing Timeline (2019)

V. Challenges

Significant enhancements have been made for DER participation in the wholesale market in just the last few years alone. While this specific resource type is a more efficient option, it is not without its challenges, as presented below.

5.1 Lack of Revenue/Equality

A key challenge facing DERs is the lack of revenue equality when compared to traditional, participating generators. This is primarily attributed to the lack of market product offerings. This includes the absence of a capacity market as found in PJM's marketplace and accessibility to frequency regulation offerings. Additionally, unlike traditional generators, DERs cannot generally amortize their cost over the long-term, creating a lack of financial certainty for wholesale market DER investment opportunities. The Demand Response Auction Mechanism (DRAM) does create an opportunity for longer term contracts and related capacity payments, but these are currently limited to 1 or 2 years and are generally not applicable for technologies that can create value outside of traditional peaking hours.

It is the intent of this demonstration project to simulate missing product offerings for DERs, such as frequency regulation and/or other market product offerings presented in ESDER Phase 3, and show that these additional services can be provided to the grid via the PDR model, and should be compensated accordingly.

5.2 DER Aggregation Challenges

Challenges remain for the creation of resource aggregations that are capable of meeting minimum size requirements for energy and ancillary service market participation. Equally challenging is the risk associated with maintaining a resource aggregation large enough to meet the same size requirements. Risk can include a customer moving outside of the designated LSE territory or even opting out of the demand response program altogether. Currently, neither Portfolio is exposed to any of the above challenges. There is a level of risk associated with expanding the aggregation of each Portfolio, should resource owners seek to incorporate more locations into their PDR. Portfolio 2, for example, is owned by the same hotel chain and as such may seek to aggregate a third hotel into their existing PDR. There is a chance that such a hotel may not fall under the same LSE. In that case, the hotel would not be able to fit within the same PDR.

The same risk applies to Portfolio 1, should the school district adopt a Community Choice Aggregation (CCA) for their energy supplier or not align accordingly with what could be shifting Sub-LAP realignments.

5.3 Demand Response Modeling

DR resource operators experience challenges in forecasting their capacity, which is critical to determining the financial viability of projects. Both Portfolios are expected to accurately forecast their available capacity to fulfill their DR event dispatch obligations. Operational constraints include variability in season/weather, occupancy, retail rates, and host-site comfort levels; all having an impact on how resources are modeled for generating revenue from wholesale market participation. Additionally, each Portfolio will have its own set of use limitations and commitment costs to participate.

For example, the storage devices in use for Portfolio 1 have minimum/maximum run-time constraints and are subject to round-trip efficiency and degradation losses. These challenges are unique to Portfolio 1 and its ability to adequately model its state-of-charge (SOC) for market participation while meeting local bill management requirements. The assets in Portfolio 2 may not align well with anticipated DR event dispatch opportunities, requiring a high degree of optimization that can preserve hotel guest comfort levels while generating any meaningful revenue from an event dispatch.

5.4 Open Issues in Wholesale Demand Response

Over recent years, the CAISO has initiated several changes to help enhance demand response participation in the wholesale markets; reducing barriers for DER participation. As indicated in the previous section, the ESDER initiative serves as a recent example of these efforts. Below are open issues in more detail, as presented in ESDER 3.

Recognition of BTM EVSE Load-Curtailment

A key ongoing issue is the inability for grid operators to recognize load curtailment contributions from behind-the-meter assets. While MGO resolved this issue for energy storage, it has been raised for possible inclusion in ESDER Phase 3 by vendors of electric vehicles supply equipment (EVSE). Olivine has supported sub-metering in general for demand response assets, noting that a compelling case for special treatment for EVSE has not surfaced. The hotels in Portfolio 2 could take advantage of sub-metering, and this may be analyzed as a part of the greater project.

Load-Shift Product

Mid-day excess solar production has lead to the curtailment of clean energy and/or negative prices in the market. Considering these challenges, the CAISO is exploring the creation of a new market product to incentivize storage resource owners to consume excess solar production from the grid shifting that consumption from times that might be less advantageous. The development of such a product was preceded by a proposal from the storage community, with many details outstanding to finalize such a product. Such details include determining the role, if any, of the LSE and applicable retail-rate implications.

VI. Conclusion

While it has been illustrated that DERs can create multiple revenue streams for participating in the wholesale market, the PDR model is not without its challenges. This report provides an initial view of revenue potential for the grid services to be tested during the STEEL project, with additional work to be done to evaluate revenue opportunities in the projects' operational phase. The lessons learned from this project will ideally help provide direction and support for continued enhancement of market rules and products that can better compensate demand-side resources to ensure a greater penetration for California to achieve its aggressive decarbonization goals. The continued collaboration among all relevant stakeholders is essential towards this effort.

APPENDIX A
REGULATORY ITEMS AND INITIATIVES AFFECTING WHOLESALE DEMAND RESPONSE[14]

Item	Description
Energy Storage and Distributed Energy Resource (ESDER) Initiative *Though not a regulatory proceeding, ESDER developments have the potential to dramatically impact the how storage devices interact with the grid, thus creating a need for future regulations that ensure these types of assets are adequately compensated.*	**Phase 1:** Enhancements made to SOC bidding parameters, empowering resource owners to self-manage limits, and enhancements made to PDR/RDRR performance evaluation for BTM resources. **Phase 2:** Enhancements to performance evaluation methodologies for PDR/RDRR, clarifications for station power, and inclusion of gas-indices into the system Net-Benefits Test (NBT) **Phase 3:** Strawman proposals primarily around Demand Response modeling limitations, multi-use application issues (notably, Microgrids), building upon Load consumption concerns, and recognition of the need to extend MGO for BTM EVSE
CPUC D.16-09-056 *Decision adopting guidance for future demand response portfolios and modifying decision 14-12-056*	This decision determined that the collection of data on fossil-fueled back-up generation in demand response programs, provides guidance to Utilities on existing demand response models, and adopts goals for demand response to assist the state's ambitious environmental objectives
CPUC R.07-01-041 (DR) *Policies and protocols for demand response load impact estimates, cost-effectiveness methodologies, megawatt goals and alignment with California ISO Market Design Protocols*	While this proceeding is closed, the final implementation of Electric Rule 24 is still outstanding. This is of specific interest because it specifies rules for bidding of bundled customers into the wholesale market by utilities and third parties. It provides new rules on roles, responsibilities, access to meter data, and liability for meter data submittal to the ISO. The

	application of the default load adjustment (DLA), covered in Section 5.3.16.3.1 DRP / LSE Contract Requirement, could impact final compensation.[15]
CPUC R.11-09-011 (Rule 21) *Improve distribution level interconnection rules and regulations for certain classes of electric generators and electric storage resources*	This proceeding aims to simplify the interconnection process for CPUC jurisdictional resources. The scope of this proceeding includes metering and technical requirements, refinement of the interconnection review process, mechanisms to improve cost certainty, cost allocation policy between ratepayers and developers of distributed generation, development of the distribution group study process, consideration of forms and interconnection agreements as well as consideration of the applicability of Rule 21 to DG programs. Note that a new interconnection proceeding is on the horizon that will likely begin to tackle DER integration issues beyond Rule 21 Interconnection.

APPENDIX B
GLOSSARY OF TERMS[16]

Term	Definition
ADS	A CAISO system that communicates real-time dispatch instructions to resources; providing instructions in 5-minute intervals.
CBL	Customer Load Baseline: Establishes a method for computing a customer's baseline load; an estimate of how much electricity a customer would have used had it not curtailed its load in response to Day-Ahead and or Real-Time event dispatch
CMRI	Customer Market Resource Interface: A CAISO application that allows market participants the ability to view prices and dispatch instructions.
CISR	Customer Information Service Request: A required form to be filled out by a participating customer that authorizes a third-party demand response provider access to meter data.
DRP	Demand Response Provider: An entity that is certified by the CAISO to provide demand response services to either a PDR or RDRR
DRS	Demand Response System: A CAISO application purposed for the collection, approval, and reporting on information for demand response resources in the wholesale market
DRRS	Demand Response Registration System: The primary interface of the CAISO for all demand response resource and location registrations. All registrants are subject to LSE/UDC review.
FNM	Full Network Model: The CAISO mapping tool for all resources and settlement points in the CAISO Balancing Authority Area.
GDF	Generation Distribution Factor: A component of bidding that accounts for how generation is delivered across a specific P-Node.
LSE	Load Serving Entity: An entity (or designated agent for) that is granted authority by the state of California to sell electric energy to a specific region within the CAISO Balancing Authority Area.

MGO	A performance methodology that utilizes the output of a behind the revenue meter generation device to calculate demand reduction during a dispatch interval.
NBT	Net Benefits Test: An ISO established price threshold in the market that ensure demand response bids are cost-effective.
NGR	Non-Generating Resource: Resource of minimum size 500 kW that act as either negative or positive load.
PDR	Proxy Demand Resource: A load or aggregation of loads that is capable of providing 100kW measurable load curtailment potential and is served by a single Load Serving Entity and falls under the same Sub-Load Aggregation Point (Sub-LAP).
RA	Resource Adequacy: California LSE's are mandated to procure capacity to meet 115% of their annual system peak load; ensuring there is a reliable quantity of capacity to serve load.
RDRR	Reliability Demand Response Resource: A resource type that capable of providing 500kW of measurable load curtailment potential for emergency purposes upon receiving a 40-minute notification.
SC	Scheduling Coordinator: An entity that is certified by the CAISO to conduct all market bidding and settlement activities, on behalf of a resource or aggregation of resources.
SIBR	Scheduling Infrastructure and Business Rules: A CAISO system that validates and publishes bids.
UDC	Utility Distribution Company: An entity responsible for the construction and management of their respective distribution grid.

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