Olivine, Inc.

Distributed Energy Resources Integration

Summarizing the Challenges and Barriers

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1 Executive Summary

The California Independent System Operator (ISO) engaged Olivine, Inc. to provide a summary report of the challenges and barriers that exist for distributed energy resources (DERs) to provide grid services. These resources, located on the distribution system, include energy storage, plug-in electric vehicle (PEV) applications, demand response and combinations thereof that include photovoltaic solar or other distributed generation resources. With a growing list of new technologies, business models and changing regulations that include 12 active CPUC proceedings, the DER landscape is increasingly complex. This report addresses DERs that generate electricity and require interconnection to the ISO as well as those that alter consumption (such as demand response) and do not require interconnection. This report does not delve into the question of whether or not wholesale integration is appropriate or the best application of DERs to meet California's electricity needs.

Many of the findings are not surprising. By far the number one barrier to entry for direct participation of demand response in the ISO, after completion of Electric Rule 24, is the lack of revenues available to resource owners from the wholesale market. Outside of the development of a long-term capacity market, the clearest approach to address this is counting bid-in demand response towards resource adequacy. There are ongoing efforts to define specifics on how to do this, from qualifying characteristics for demand response to market constructs for compliance and settlements. This issue is a long-term effort but one of the highest priorities for direct integration.

There were six other key areas identified as having the most impact in advancing DER participation in the ISO markets. The first four of these items are ISO specific while others will require a greater level of coordination with other agencies. The first item in particular is ISO specific and expected to have the greatest impact. The impact anticipated for the following five were indistinguishable from each other during the analysis. These areas, described in detail in the report, are:

1. ISO metering and telemetry
2. Sub-LAP and LSE aggregation boundaries
3. Ancillary service certification process
4. Resources whose capacity or operating maximum may vary (dynamic capacity)
5. Shared-purpose DERs such as microgrids
6. Interconnection process for wholesale participation (WDAT)

Specific suggested actions for the ISO include:

1. Completion of phases 1 and 2 of expanding the metering and telemetry stakeholder process to address the constraints and associated costs that are limiting innovative resource types and business models. Phase 1 includes several items distinct items addressing these issues, while phase 2 targets the creation of a new market entity: the data concentrator, a third party with legal standing at the ISO to provide metering and telemetry services for a resource owner.
2. Consider allowing resources to span sub-LAPs and possibly span LSEs.
    - Near-term participation of demand response in ISO markets will be through existing IOU-based demand response programs. The mismatch between the alignment of resources in utility programs and the current sub-LAPs make it extremely difficult to register even subset portfolios of customers currently enrolled in utility programs let alone to convert an entire utility program into PDR resources. These, as well as LSE issues, are chief among the incompatibilities between these programs and the wholesale

market, creating a significant barrier for integration of demand response from those programs.

3. Evaluate alternative ancillary services (AS) certification processes better suited for demand response and DERs.
    - Current ancillary service certification tests for DERs that provide dynamic capacity due to weather sensitivity or PEV integration are extremely challenging. They may require frequent re-certifications for distributed resources that would significantly impact operations and diminish the results of the capacity test; however, re-certifications are not required when the capacity may be reduced due to weather or availability issues.
4. Introduce bidding rules to address resources whose operating maximums vary dynamically.
    - With proper forecasting techniques, resources whose maximum capacity may be dynamic or variable (such as storage or weather dependent resources) can meet their awarded quantities; however, some bidding rules require availability up to a resource maximum that may not be achievable on a given day. This creates a financial risk that resource owners are unable to accurately assess and address.
5. Identify options for supporting shared-purpose DERs so that many microgrid and electric vehicle projects could avoid full interconnection.
    - This evaluation should include enhancing PDR for frequency regulation and capacity-only frequency regulation. This would eliminate the need for a wholesale energy settlement and subtractive or logical metering to remove wholesale activity from a retail scenario where non-demand response resources are behind a whole premises.
6. Provide guidance to stakeholders to clarify the interconnection process for wholesale participation (WDAT).
    - The complexity of the interconnection process for resources that both supply and consume energy has kept these resources from engaging in the wholesale market.

While the timeline for the completion of this report did not support a lengthy research or analysis effort Olivine's direct experiences with resource owners, other market participants and stakeholders coupled with discussions with ISO personnel supported the quick completion of this document.

The following five DER configuration scenarios were used as a framework to assess challenges and barriers to wholesale market participation:

1. Dedicated facility: Base case for DER providing wholesale service only.
2. Behind-the-meter: DER providing wholesale service behind a whole-premises meter; sharing the resource for retail services.
3. Extra-facility: DER providing wholesale and retail service external to whole premises meter(s).
4. Aggregation variant: DER composed of sub-resources providing wholesale service
5. Dynamic Capacity Variant: storage including electric vehicles and/or DR with dynamic capacity due to shared use or weather sensitivity.

Obstacles associated with each of these scenarios were categorized, and a list of mitigating actions identified. Subsequently, these items were scored based on a two-axis scoring methodology of effort and impact. While the scope did not include the development of quantitative data and there are a significant number of interdependencies among these issues, this diagram is intended to serve as a basis for prioritization and additional review. Below is a scatter plot of the actions included in the analysis.

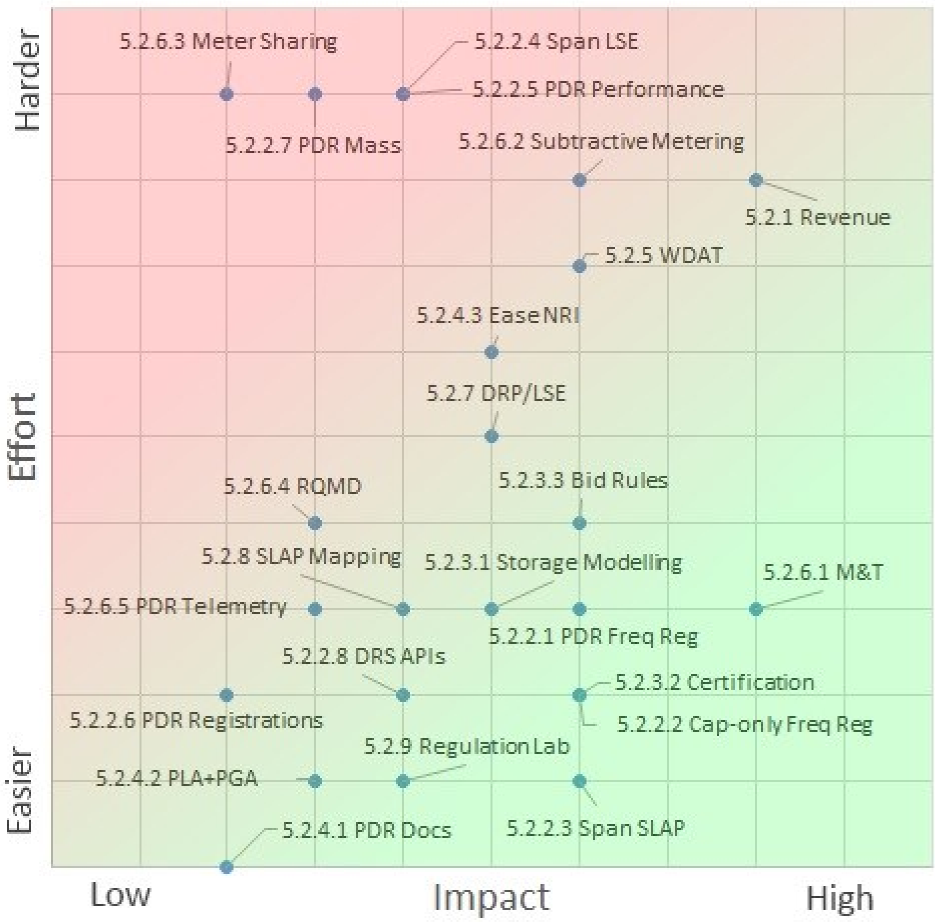

Figure 1: Impact and Effort

Resolution of many of the issues are long-term and complex in nature, involving more than one agency. However significant progress in grid integration of DERs can be made by the ISO both independently and in collaboration with other agencies and stakeholders. Olivine believes that an understanding of these issues is critical to the energy future of California and to that end contributed effort to co-fund the completion of this report. We are hopeful that this report will be a catalyst to help unite the various discussions around these issues and provide direction for valuable conversation among stakeholders.

We urge the ISO to consider the implications of each of the barriers and prioritize the specific actions to provide a pathway for DERs to the grid.

2 Introduction

Distributed energy resources (DER) will be a valuable part of the resource mix to ensure reliable management of the green electric grid. Currently, there are significant barriers and challenges for these resources to provide grid services. The purpose of this report is to identify and summarize these challenges and barriers. These resources are located on the distribution system and include energy storage, plug-in electric vehicle (PEV) applications, demand response, and combinations thereof that include photovoltaic solar.

This report addresses DERs that generate electricity, and therefore require interconnection to the ISO, as well as those that alter consumption (demand response) that do not require interconnection. The interconnection requirement is important because the related requirements are the source of many of the challenges and barriers for new resources. For those resources requiring interconnection, of particular interest are bi-directional resources where both generation and energy procurement occur. This is because the existing regulatory and policy framework for the integration of generation-only resources is well understood; however, the introduction of bi-directional resources exposes new issues.

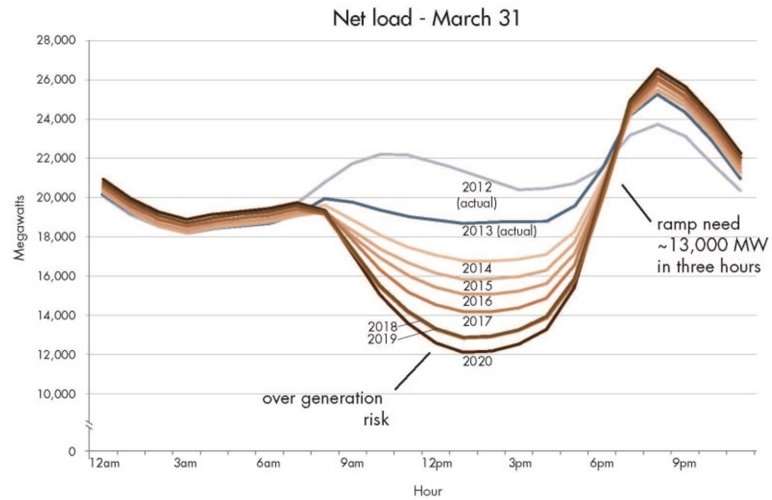

Figure 2: The "duck curve": The Changing Net Load Pattern[i]

California is in the midst of a major shift in the system net load curve[1]. This curve has steepening ramps and the potential for over-generation. This shift is primarily caused by the increasing penetration of renewables, particularly distribution and transmission connected solar, coupled with the risk of retirement of once-through-cooling power plants. To help solve these issues, California is pursuing aggressive distributed generation and storage procurement targets. These initiatives are critical, and it will take the efforts of many to bring innovative technologies and business models to bear for successful implementation.

Candidate businesses enabling and implementing distributed energy resources – including automotive manufacturers, storage entrepreneurs, and innovative aggregators – find many challenges to bringing solutions to the wholesale market, and in some cases, barriers that block entry entirely.

While on one hand there is demonstrated value in new DER technologies, there is also some uncertainty of the value of certain DER types directly participating at the wholesale level. There is also a lack of consensus on how to best utilize these different types. For example, Vehicle Grid Integration (VGI) can certainly provide frequency regulation to wholesale markets, but perhaps a retail rate supporting managed charging solution might be a better fit in the near term. Without a consensus on how such technologies should be deployed, there is a risk that some projects are unworkable beyond a pilot phase, because there is no market or regulatory construct to support on an ongoing basis. Further, the inherent costs of wholesale participation may never make business sense for certain types or sizes

[1] The system net load curve is the system demand minus the intermittent renewable generation.

of DER. If such pilots cannot be feasibly replicated without pilot status, the costs remain too high, or there is too much of a mismatch with the technology, then resolving the related barriers should likely be made a lower priority.

This report identifies issues for which the ISO is responsible, but also issues that are under the purview of the Federal Energy Regulatory Commission (FERC), the California Public Utilities Commission (CPUC), and the California investor-owned utilities (IOUs), with the intention that it be a starting point to identify and mitigate challenges and remove barriers.

3 Background

This section provides background information to provide context to understand the different challenges, barriers, and recommended actions to advance DER provision of grid services. This section includes the various ways that DERs can be combined and where these resources can be located. It also includes a brief description of the ISO process that DERs must go through to participate in the wholesale market. Finally, a brief description of the current relevant CPUC proceedings is provided.

3.1 DER Implementation Scenarios

To better understand the challenges and barriers to DERs providing grid services, it is helpful to start with a description of the scenarios under which DERs are implemented and currently supported in the ISO market. None of these scenarios are hypothetical; all are in some form of project development today. Specific projects are identified only when those projects are public; in many cases, project details are confidential.

The following table summarizes the implementation scenarios in this report:

	Scenario	Description
3.1.1	Dedicated Facility	Base case for DER providing wholesale-only service with no retail component.
3.1.2	Behind-the-meter	DER providing wholesale service behind a whole-premises meter, possibly sharing the resource for retail services.
3.1.3	Extra-Facility	DER providing wholesale and retail service, external to whole premises meter(s).
3.1.4	Aggregation Variant	DER composed of sub-resources providing wholesale service.
3.1.5	Dynamic Capacity Variant	Storage, electric vehicle, and DR applications with dynamic capacity due to commitments to other use, physical disconnection, or weather sensitivity.

Table 1: Scenarios

Of particular interest is how to support behind-the-meter resources within a facility that provides wholesale market service within the retail context (see Section 3.1.2). Although many customer-side technologies can provide benefit to the grid, providing both wholesale and retail service will help them achieve their ultimate value potential. Another relevant issue is how to aggregate useful resources for the wholesale market, while taking advantage of innovations in control, metering, and telemetry. Current policies prohibit or make the use of innovative technologies difficult[2].

This document does not directly address microgrid or virtual power plant as scenarios because the related issues are covered by other scenarios. We understand that the ISO has an interest in determining how to model such resource types and if, in fact, they require unique treatment.

A summary of how these DER integration scenarios interact with challenges and barriers is included in Section 4, Challenges and Barriers.

[2] One example is with aggregations of customer-sited storage resources. Innovations in metering and telemetry that allow greatly reduced cost and improved resource-owner operations fail to meet ISO requirements. See Section 4.7 for more information.

3.1.1 Dedicated Facility

This scenario is included as the base case of a DER providing services to the wholesale market from a dedicated facility that has no other energy flows as the simplest and most straightforward. The DER is metered by the ISO and UDC.

- An example is a large distribution-connected storage resource providing all of its service to the ISO markets.
- This case does not apply to DR.
- This case looks identical to a conventional grid-connected ISO resource.

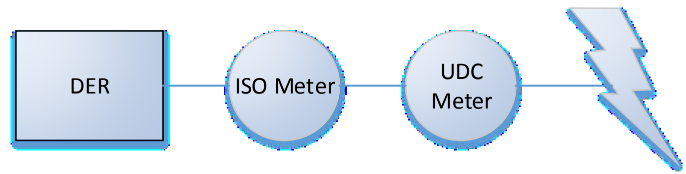

Figure 3: Dedicated Facility

3.1.2 Behind the Meter

This scenario includes variations when a resource is behind a whole-premises utility meter.

3.1.2.1 Behind the Meter, Load Only

This load-only scenario includes a resource that provides demand response to the wholesale market while also providing benefit to the customer on the retail side.

- PDR supports this case; however, it is currently limited to energy and non-spinning reserves.
- This is the simplest method of integrating with the ISO.
- The resource in this case may just be controllable load (e.g., an HVAC system) within a larger, uncontrollable load.
- ISO metering is derived from a 10-in-10 baseline with day-of adjustment capped at 20%[iv].
- This case expressly supports aggregations of such sub-resources into one market resource.

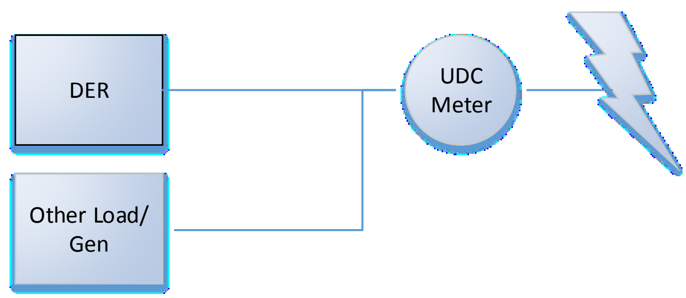

Figure 4: Behind the Meter, Load Only

3.1.2.2 Behind the Meter, Exporting

This scenario includes a resource wholly metered by the ISO, but in a facility behind a whole-premises utility meter. All activity metered by the ISO is settled in the wholesale market. This differs from the Load-Only scenario in that it allows export across the whole premises meter and/or supplies spinning reserves or frequency regulation to the wholesale market.

In general, such scenarios would also benefit a customer on the retail side; however, such resources today are limited to wholesale participation due to an inability to separate wholesale from retail metered quantities.

- For example, a storage resource could provide frequency regulation to the ISO and customer demand charge mitigation.
- Such resource sharing could occur exclusively during non-overlapping periods or in parallel by sharing the underlying DER capabilities.

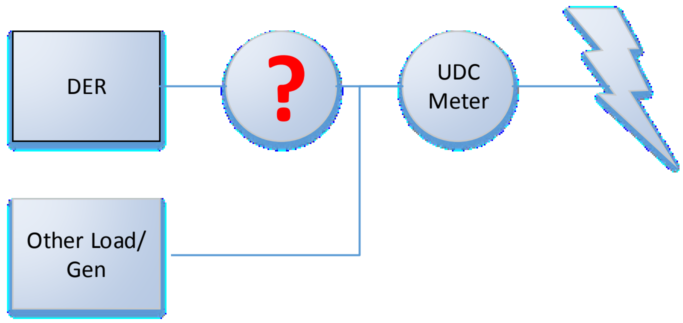

Figure 5: Behind the Meter, Exporting

When sharing retail and wholesale, the ideal metering configuration for the ISO and UDC is unclear[3] and represented by a question mark in the diagram. Of particular interest in ongoing projects is that such sharing to provide wholesale grid services as well as customer-side benefit is the ultimate goal; however, without new product development by the ISO or other virtual metering techniques, there is no clear path forward.

3.1.3 Extra-Facility

This scenario includes a resource that provides service to the wholesale market while also benefiting one or more customers. Different from the previous scenario, in this scenario the resource site is at or near a customer facility, but not behind the utility meter. Resource capabilities are provided to both the wholesale market and retail customer(s).

- For example, a large storage resource sited next to a business park, such as the PG&E Yerba Buena Battery Energy Storage System Pilot Project[iii].
- In one specific case, the ISO will be directly polling multiple meters and performing subtractive metering[4]; however, the ideal metering configuration for this scenario is unclear.

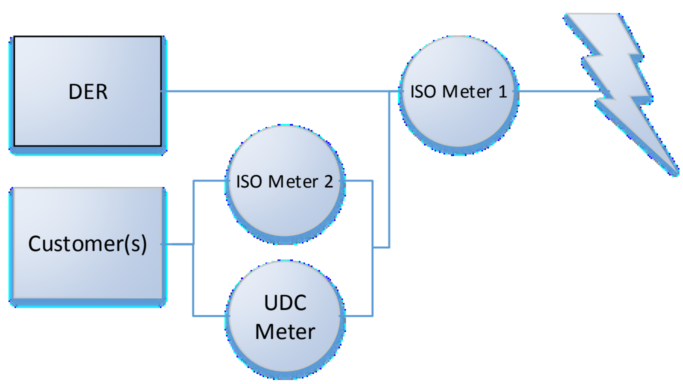

Figure 6: Extra-Facility

3.1.4 Aggregation Variant

This scenario represents an aggregation of smaller distributed resources at different locations, providing service to the wholesale market as a single resource.

[3] One can make a behind-the-meter solution work in an "all or nothing" configuration with electrical switchgear; however, the expense of such a solution makes it out of reach for many projects and is not a supported configuration for the ISO.

[4] In general, subtractive metering is calculating the difference between two metered points. This is a technique to determine the energy being consumed net of a sub-metered entity. In the extra-facility scenario, the difference is calculated between ISO meter 1 and the UDC meter, computing the usage of the DER.

- One example is an aggregation of the scenario described in Section 3.1.2.2, such as an electric-vehicle service provider delivering wholesale services within a geographic area.
- The default metering for this scenario includes ISO polled meters at each sub-resource location. This creates challenges for the ISO when such aggregations begin to include a large number of smaller distributed resources because the ISO m need to manage the aggregation of a large number of meters for a participant. A preferred metering configuration for this scenario has not been fully defined and implemented.

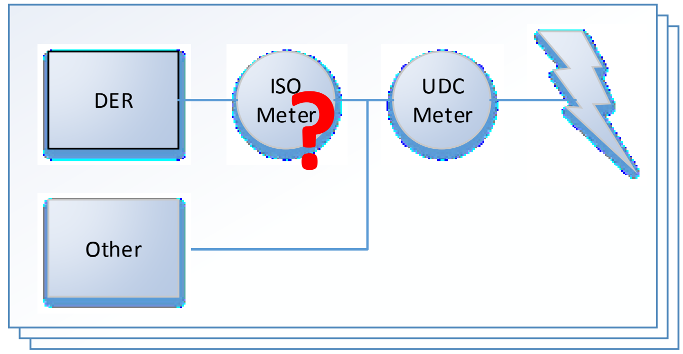

Figure 7: Aggregation Variant

3.1.5 Dynamic Capacity Variant

This scenario represents a resource that has a variable maximum capacity that can be made available to the wholesale market. This is distinguished from conventional generators which may have a fixed maximum output (e.g., 100 MW); however, dynamic capacity resources may have maximums that vary widely by season, day, or even hour depending on weather, availability of sub-resources, or commitments to other uses. Examples of such scenarios include:

- A storage resource provided exclusively from batteries within PEVs. When these vehicles are not connected to the charging station, they are not available to the aggregate resource.
- Weather-dependent demand response.
- A storage resource providing customer-side benefit (e.g., demand charge mitigation) as well as wholesale service. The maximum capacity available from the resource could be dependent on time of day and weather.

Note that storage, vehicle and DR scenarios are not necessarily dynamic by this definition. For examples, a PEV fleet providing frequency regulation and a manufacturing process providing demand response energy may both have fixed maximums.

Without fixed resource maximums, there are impacts to the resource owner to manage certification tests and ongoing market operations effectively, but this issue does not imply an inherent reliability problem. For example, with proper forecasting techniques, such resources can meet their awarded quantities; however, some bidding rules require availability beyond awarded quantities up to a resource maximum that may not be achievable on a given day.

3.2 ISO Implementation Processes

There are two distinct pathways for DER implementation at the ISO, depending upon the resource type and products for resource participation.

The first process is for conventional and non-generation resources (NGRs) including energy storage. This is referred to as the New Resource Implementation (NRI)

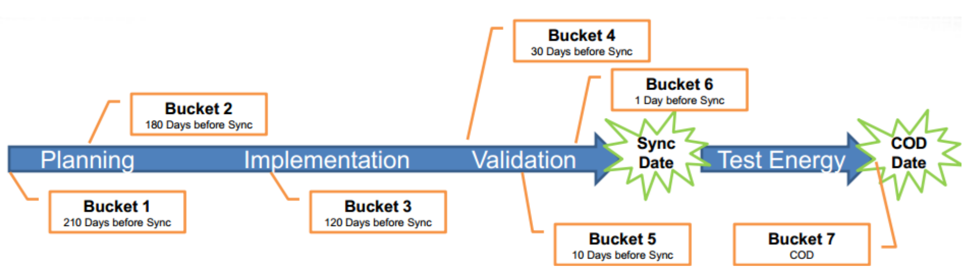

Figure 8: ISO Implementation Process[ii]

Process shown in Figure 8. This process is relevant for any resource at the ISO that requires a full interconnection in all of the identified scenarios. This process consists of several high level phases, with specific requirements and timelines defined within "buckets", which can take the better part of a year.

The initial buckets 1 and 2 focus on planning and include aspects required to model the resource in the full network model[5]. Steps include providing resource line drawings, metering and telemetry information, meteorological site information, communication plans, and the interconnection agreement between the resource owner and the utility distribution company. In particular, this agreement is the applicable wholesale distribution access tariff (WDAT) agreement. During project implementation, bucket 3 includes executing several agreements with the ISO and providing initial resource attributes in a generator resource data template (GRDT). At the end of the implementation phase, bucket 4 includes providing the final GRDT, final telemetry, metering information and other relevant agreements. Validation starts in buckets 4, 5, and 6, bringing the resource online at the initial synchronization date. Bucket 7 results in a final commercial operation date approved by the ISO.

The second process is for proxy demand resources (PDRs). This case targets existing facilities – generally industrial or commercial – that are able to shed load in response to market instructions. This process can be used for the behind-the-meter load scenario. The entire process is much simpler for several reasons, including: (1) meter data is submitted leveraging existing utility metering eliminating the need for parts of the NRI process; and (2) for pre-defined PDRs there is no need to model the resource in the full network model. As a result, the process is primarily to ensure that locations identified to supply demand response are eligible and validated by the utility distribution company and load serving entity. This entire process can be completed within thirty daysif the required agreements are in place and given a set of customer locations that meet the minimum requirements. This process interleaves with the NRI process previously identified in the case where a PDR requires telemetry or customized resource modeling. The former is required for ancillary services and for PDRs greater than 10 MW in size. The latter may be desirable for a resource owner because modelling can more accurately reflect nodal prices (see Section 4.4.1 NRI Process for PDR).

Figure 9: Registration of Predefined PDR

[5] The Full Network Model represents the power system under ISO control, including all resource capabilities and network constraints.

3.3 Regulatory Items Affecting DER Implementation

There are many proceedings underway affecting DERs and their participation. This section identifies these proceedings and the relevant issues.

Item	Core Issues
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 4.3.1 DRP / LSE Contract Requirement, could impact final compensation.
CPUC R.13-09-011 (DR) *Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements*	This new proceeding introduces the concept of bifurcation of demand-response into "supply-side" and "demand-side" categories. The intention is that supply-side DR resources are a better fit with the wholesale market, while demand-side resources would continue to play a bigger role in addressing local distribution issues including shaping system load profiles over time. The proceeding aims to refine these terms and to determine which specific programs and rates fit into the two categories. There is some discussion of making only bid-in DR qualify for resource adequacy and thus, tied to capacity payments. This proceeding may result in the creation of longer (i.e., 5-10 year) funding cycles for demand response, which may increase the volume of preferred resources available.
Joint Reliability Framework *Provide additional opportunities for preferred resources, including demand response, to compete to meet capacity requirements in the two and three year-ahead time frames*	The current proposal plans to augment existing 1-year resource adequacy (RA) obligations by adding both 2-year and 3-year obligations for all LSEs in the ISO balancing authority. It also suggests the development of an ISO-run capacity auction to replace the existing backstop mechanism and provide a voluntary venue through which LSEs can procure forward capacity beyond what they get bilaterally. Additionally, it proposes the publishing of a 4-10 year forward joint reliability planning assessment. Among other reasons, this framework is important because it could create a more reliable revenue stream for DER.
CPUC R.10-12-007 (Storage Procurement) *Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage System*	While this proceeding is closed, it is relevant to DER because it set storage procurement targets for the IOUs, CCAs, and ESPs for the years 2014-2020 creating the likelihood of a significant amount of storage capacity available as DER for use by the grid.

CPUC R.09-08-009 (PEV) *Consider alternative-fueled vehicle tariffs, infrastructure and policies to support California's greenhouse gas emissions reduction goals*	While this proceeding is closed, the main relevance to DERs in this proceeding was sub-metering for PEVs in support of electric vehicle service providers and alternate PEV-only rates. Many parties are hopeful that this proceeding will develop a sub-metering protocol that would help to address measurement issues outlined in this report, vehicle grid integration efforts, as well as other end-uses.
CPUC R.13-11-007 (PEV) *Consider Alternative-Fueled Vehicle Programs, Tariffs, and Policies*	Succeeding R.09-08-009, this proceeding will establish policies and procedures that facilitate utility participation in vehicle-grid integration. Specifically, it will cover new tariffs, pilot programs, rates and financing strategies designed to encourage electric vehicle integration. In the first track of the proceeding, assessment of vehicle-grid integration value will include the potential of using PEV batteries for demand response, storage and ancillary services.
CPUC R.11-10-023 (RA and FRACMOO) *Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations*	Connects the resource adequacy construct to the wholesale market including DR and energy storage resources. Flexible capacity procurement obligations have been adopted for LSEs. Rules for counting preferred resources towards this requirement are being developed jointly by the CPUC and the ISO. The CPUC has proposed methods that calculate the Effective Ramping Capability and Effective Load Carrying Capability for these resources. The ISO is developing specialized Flexible Resource Adequacy Capacity Must-Offer Obligations (FRACMOO) including accommodations that recognize demand response use limitations.
Default Load Adjustment (DLA) Applicability (ISO vs. FERC) *The ISO has appealed the FERC denial of rehearing of applicability of the default load adjustment to prevent double payment for DR*	In July 2013, after a variety of Tariff and compliance filings related to PDR, RDRR and FERC Orders 745 and 745A, FERC ultimately denied rehearing on applicability of the DLA for DR compensated at LMP at or above the net benefits test (NBT). The ISO has appealed in US District Court. Ultimately, this issue may impact the need for financial settlements between LSEs and DRPs. The current rules eliminate the DLA for DR paid at or above the NBT.The DLA will only be applied to the LSE in rare circumstances and will generally have little impact on LSE settlement. If the DLA were to apply to all DR awards, the presence of a persistence DLA will likely incent LSEs to ask for compensation from the DRP.
CPUC R.12-11-005 (DG & Net Metering) *Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues*	The main work of this rulemaking is to assess and refine the incentive programs available for various distributed generation technologies, primarily focused on the oversight and refinement of the California Solar Initiative and the Self-Generation Incentive Program. Additionally, the proceeding addresses the development of general distributed generation policy issues on the customer-side of the meter such as net-energy metering (NEM), implementation of the NEM cap calculation and distributed generation interconnection.

CPUC R.08-12-009 (SG) *Consider Smart Grid Technologies Pursuant to Federal Legislation and on the Commission's own Motion to Actively Guide Policy in California's Development of a Smart Grid System*	This proceeding covers smart grid deployment plans including the creation of metrics by which IOUs must report progress. It also addresses the rules regarding privacy protections for customer energy usage data as well as the extension of those rules to gas corporations, community choice aggregators (CCAs) and energy service providers (ESPs). Recent discussion has centered on the costs and benefits of the creation of an energy data center to consolidate multiple data sources into one, easy-to-access repository.
CPUC R.12-03-014 (LTPP) *Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans*	The Long-Term Procurement Planning (LTPP) proceeding addresses the long-term need for new system and local reliability resources, including the adoption of system resource plans and the assessment of long-term local area reliability needs. Every two years, LTPP reviews the IOU ten-year procurement plans. Additionally, it provides a forum for consideration of the various assumptions used for forecasting reliability needs such as the early retirement of the San Onofre Nuclear Generating Station (SONGS) & Diablo Canyon facilities. The ISO and CEC Integrated Energy Policy Report (IEPR) forecasts that are used as inputs to these planning efforts include assumptions about the availability and impacts of EE and DR.
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.

4 Challenges and Barriers

This section provides summaries of the challenges and barriers related to DER integration, grouped into relevant categories. Although many of these topics are complex enough to warrant further independent studies, the scope of this report is to provide enough guidance for ISO regulatory priorities and project planning. Note that some of the challenges and barriers are independent, while others relate more closely. In addition, many items have implications that cut across FERC, ISO, CPUC, and IOU boundaries.

The following table summarizes the relevance of the items in this section to the previously defined DER implementation scenarios.

	Challenge / Barrier	Dedicated	BTM Load	BTM Export	Extra-Facility	Aggregations	Dynamic Capacity
4.1	Lack of Revenue Equality / Opportunity	✓	✓	✓	✓	✓	✓
4.2	Behind the Meter Issues		✓	✓		✓	✓
4.3.1	DRP / LSE Contract Requirement		✓			✓	✓
4.3.2	Timely Access to Meter Data		✓			✓	✓
4.4.1	NRI Process for PDR		✓			✓	✓
4.4.2	Participating Load and Generation Agreements	✓		✓	✓	✓	✓
4.4.3	Non-exporting NGRs Require Interconnection Agreement	✓		✓	✓	✓	✓
4.5.1	Storage Modeling	✓		✓		✓	✓
4.5.2	Ancillary Services Certification Tests	✓	✓	✓	✓	✓	✓
4.5.3	Maximum Generation and Certified Quantities	✓	✓	✓	✓	✓	✓
4.6	Wholesale Distribution Access Tariff	✓		✓		✓	✓
4.7	Metering and Telemetry Challenges	✓	✓	✓	✓	✓	✓
4.8	Aggregation Boundaries	✓	✓	✓	✓	✓	✓
4.9.1	Baselines and Sub-metering		✓			✓	✓
4.9.2	Inflexibility of Demand Response System and Processes		✓			✓	✓
4.10	Inability to Test New Technologies for Regulation	✓		✓	✓	✓	✓

Table 2: Scenario Mapping

4.1 Lack of Revenue Equality / Opportunity

Applies across all scenarios.

Currently there is no clear path to revenue equality for DERs in California wholesale markets that is on par with what is available to traditional generation resources. For the traditional generator, responding to long-term procurement process (LTTP) request-for-offers sets in motion a series of known processes and a path to long term contracting that provides the basis for financing to develop a project. This process can include acknowledgment to the cost of new entry (CONE) to amortize costs over a longer period than might even be captured in the LTPP. The assurance of a long-term contracting construct reasonably assures the recovery of development and operating costs with the risk shared between the LSE and project developer.

In addition to the lack of a long-term opportunity for DERs, there is also no functional near-term path for any consistent revenue opportunity in the wholesale market. Traditional generation that becomes "stranded" due to the lack of continued long-term commitment is able to recover ongoing operating costs through these contracts due to their ability to qualify for resource adequacy. Small DERs do not have this opportunity that provides financial certainty to support investment.

The current consideration of an intermediate contracting time horizon to bridge the gap between the annual RA contracting and the LTPP is a step that might induce dual purpose DER to integrate into the wholesale market so long as other operational issues can be addressed.

In particular, for demand response, the number one barrier to entry of demand response in the ISO, after the completion of Electric Rule 24, is the lack of revenues available to resource owners from the wholesale market. Outside of the development of a longer-term capacity market, the clearest solution will be counting bid-in demand response towards RA. The specifics on qualifying characteristics as well as market constructs for compliance and settlements, however, are still outstanding.

Demand response lacks the opportunity for access to two higher value products at the ISO: spinning reserves and frequency regulation. A change to allow the former is underway and will be available in late 2014 once the Western Electric Coordination Council (WECC) new standard becomes effective[6]. New products or product enhancements will be required for DR to provide frequency regulation.

Possible Actions

5.2.1	Improve Revenue Equality and Opportunity

4.2 Behind the Meter Issues

Applies to behind the meter scenarios.

Many customer-side use cases and business models envision providing value through savings on the retail bill (e.g., by reducing peak demand) along with wholesale market participation in behind-the-meter applications. PDR was designed to support this scenario for energy and non-spinning reserves; however, NGR resources do not. As a result, frequency regulation cannot be provided in such a shared scenario. An NGR would include a whole-premises utility meter and include an additional wholesale meter expressly for the purposes of wholesale market settlement.

There are two related issues that this raises today with this dual metering: (1) DER activities are reflected in both the wholesale market and retail billing concurrently and fully; and (2), energy used or consumed is reflected in both meters. These issues are similar and overlap; however, the former is about sharing a single resource at specific times (or a fractional resource constantly) while the latter is an issue of double energy settlement.

For example, in the former issue the ISO meter will measure a resource 24 x 7, regardless of whether there are awards for the wholesale market. Even if the intention is to provide a wholesale market service during certain hours, all hours will be settled in the market[7]. With the latter issue, any energy that crosses the wholesale meter will be treated as wholesale procurement, but since the source of that

[6] Spinning reserves has the requirement to be responsive to frequency deviations immediately and automatically. For demand-side resources this requires being able to drop 10% of load within 10 seconds.

[7] Without market awards, metered values will be settled as positive or negative real-time uninstructed energy.

energy likely comes from the distribution grid, the resource owner will also have to pay for the energy at the retail rate.

Both issues today are resolved within the PDR product. Specifically, the temporal aspect is resolved because in the PDR case there is no wholesale settlement process without an award. In addition, the energy issue is moot because curtailed load nets out of the retail meter. Unfortunately, this solution is incomplete: PDR supports neither spinning reserves nor frequency regulation, and NGR is essentially agnostic to behind-the-meter scenarios leaving any issues to be resolved by the resource owner and distribution utility.

A concrete example exists on the Los Angeles Air Force Base Vehicle to Grid Pilot Project (LA AFB V2G Project). In this instance of Scenario 3.1.2.2, the resource is an NGR providing frequency regulation and other products to the ISO, all behind the retail meter. All charging and discharging of the vehicles results in wholesale settlement as well as retail energy consumption or net against other loads. To manage these issues of procurement and settlement, SCE is acting as the Scheduling Coordinator in the ISO market, adjusting the retail bill accordingly, based on invoiced amounts from the ISO. This solution, while perhaps workable for an IOU with their own energy customer, does not offer a standardized solution that applies to broad adoption.

Possible Actions

5.2.2.1	Enhance PDR for Frequency Regulation
5.2.2.2	Add Capacity-only Frequency Regulation
5.2.6.2	UDC subtractive and/or logical metering

4.3 Third-Party Issues

The ability for third parties to participate in wholesale market activities was central to the design of PDR as well as a major part of the efforts around Electric Rule 24. The responsibilities of the utility distribution company (UDC) and load serving entity (LSE) were identified and a new role, the demand response provider (DRP), was defined. Given this design, DRPs can work independently of the LSE, bidding demand response to the ISO while the LSE continues to schedule their customer load without needing to “carve out” the bid-in DR. Principal among this delineation of roles is the right of a customer to choose a DRP independent from their LSE and UDC. More than supporting customer choice, this ability also supports innovation by enabling third parties to contemplate and implement new technologies and business models in support of demand response. There are however, two major challenges to implementing PDRs within this model, covered below.

4.3.1 DRP / LSE Contract Requirement

Applies to behind the meter scenarios.

While the design of PDR delineates the roles of DRP and LSE, there are requirements placed on DRPs that create possible barriers to integration.

The first issue is that the ISO requires the DRP to have an agreement with the LSE as a precondition for registering any locations that use that LSE. This constitutes a significant challenge since there is no legal or regulatory basis to compel an LSE to make such an agreement. More significantly, the underlying customer may be effectively barred from choosing a DRP without their LSEs permission. In practice, DRPs may avoid recruiting customers unless there is a pre-existing relationship with the relevant LSE (i.e., the ESP for direct access customers or the IOU for bundled customers). Another likely scenario is that LSE-DRPs effectively "own" their customers demand response if they are unwilling to sign such agreements. An outstanding issue regarding financial settlements for the Default Load Adjustment (DLA)[8] may also make it harder to complete such agreements.

A related issue is that there is no clear process or requirement for an LSEs to register in the ISO Demand Response System (DRS), and ensure that they engage in the requisite validation process. Without this, it places an additional burden on the DRP to include such a requirement in the agreement with the LSE.

Solutions to these issues could include mandatory DRS enrollment by all LSEs in California and standardized DRP/LSE contracts approved by the CPUC.

Possible Actions

5.2.7	Establish Rules and Pro-forma Agreements for DRP / LSE Cooperation

4.3.2 Timely Access to Meter Data

Applies to behind the meter scenarios, aggregations, and dynamic capacity.

Third-party access to meter data, particularly to fulfill ISO requirements and timelines for delivery of settlement-quality meter data (SQMD) for financial settlement was a significant issue in Electric Rule 24 stakeholder discussions. These steps, abbreviated, are:

- The UDC collects raw premises meter data.
- An entity performs validation, editing, and estimating (VEE) to the meter data to correct errors and missing data. Such data, once finalized, are referred to as retail-quality meter data (RQMD).
- An entity applies Distribution Loss Factors (DLFs) to the RQMD, and aggregates it for the entire PDR registration for ISO settlement purposes (i.e., into SQMD).
- The scheduling coordinator (SC), as an agent for the DRP, submits the SQMD to the ISO.

[8] While the intention of the CPUC was to avoid the DLA altogether by imposing the NBT as a price floor on energy bids, the DLA will still surface when a resource provides additional uninstructed energy above a day-ahead energy award.

Aside from the clear responsibilities for the UDC and SC in the backend of this process, the steps in the middle are less clear. While the UDC performs these functions for billing purposes, the timing[9] and liability for the accuracy of the RQMD put increased burdens on the IOU[9].

Not only is this an outstanding issue in general, but the ultimate resolution of Rule 24 will likely leave the IOUs to each develop their own processes for supporting this function.

Possible Actions

5.2.6.4	Standardize process for and access to RQMD

4.4 New Resource Implementation (NRI) Challenges

4.4.1 NRI Process for PDR

Applies to behind the meter (load only) scenarios.

The ISO has been consistently improving the New Resource Implementation (NRI) Process. This includes better and more complete documentation along with a plan for more frequent network model builds. Although NRI is an inherently complicated process, there are adjustments that could help with the integration of PDRs and DERs in general.

While one might expect the NRI process to cover PDR, NRI at the ISO targets interconnection specifically and leaves out the implementation of this resource type. Specifically, PDR implementation is not covered in the NRI Guide and Checklist; however, two aspects do apply: full network model builds for non-predefined[10] PDRs and any PDR that requires telemetry[11]. In addition, there is no NRI analog for PDR implementation. As a result, PDR implementers need to incorporate several related documents and business practice manuals while also navigating relevant portions of the NRI process to understand the full breadth of requirements of implementation.

Solutions to this issue could be updating NRI documentation to cover PDR directly, or perhaps more helpful, to create a parallel set of documentation that targets PDR to the same level of detail as is covered in NRI.

There may be other cases where developing documentation sets, or cookbooks, for specific DER applications could also be helpful.

Possible Actions

5.2.4.1	Enhance Documentation of PDR Integration Process

[9] Often VEE procedures are undertaken for an entire billing period; however, to meet the specific market timelines for the submission of SQMD at T+8B and T+48B, the IOUs would need to perform VEE more frequently and closer to the market trade date.

[10] Predefined PDRs are preexistent in the full network model and can be brought to market quickly. A DRP may choose to “custom” model a PDR, requiring inclusion in the full network model build and a longer lead time.

[11] Telemetry is required for any PDR with a capacity of at least 10 MW or that will participate in ancillary services.

4.4.2 Participating Load and Generation Agreements

Applies to dedicated facility, behind the meter (exporting), and extra-facility scenarios.

One requirement for interconnection is to execute a participation agreement with the ISO. The type of agreement depends on the resource model.

The Participating Load Agreement (PLA) is an agreement between the ISO and entities serving load and/or providing responsive load to the ISO through a direct interconnection (e.g., Participating Load and NGR). The Participating Generation Agreement (PGA) is a similar agreement, but for those providing generation to the ISO.

Because an NGR can act as a generator or load, NGR resource owners need to execute both the PLA and PGA. It would be simpler for both parties if there were a single combined agreement that considered both the load and generation sides of NGR.

Possible Actions

5.2.4.2	Combine PLA and PGA for NGR Implementation

4.4.3 Non-exporting NGRs Require Interconnection Agreement

Applies to the behind the meter (exporting) scenario.

Demand response provided to the ISO through PDR does not require an interconnection agreement. On the other hand, an NGR made up of a storage device with no opportunity to generate above the facility load, must always go through the full NRI process. For example, in many projects the generation capability of the DER is dwarfed by the related facility's load, rendering the export of energy extremely unlikely during normal operations. Hardware and software controls could be implemented to take this one step further and guarantee no export, making such DER applications equivalent to DR. In such cases, it may be feasible to eliminate the WDAT requirement using the same FERC treatment that is applied to PDRs.

Regardless, the lack of an NGR model designed for the demand-response case is ultimately what creates this challenge; however, a streamlined NRI Process for non-exporting NGRs could provide value as an alternative to expanding the capabilities of PDR.

Possible Actions

5.2.4.3	Evaluate Streamlining NRI for Non-exporting NGRs

4.5 Incompatibilities with Conventional Generation

The primary design of ISO resource models and market products were for conventional generation to serve end-use load. While the PDR and NGR resource types at the ISO begin to address this from one perspective, the unique characteristics and variability implied by such resources is not reflected at the ISO. This section covers those challenges that are unique to these incompatibilities.

4.5.1 Storage Modeling

Applies across all scenarios.

For battery-based storage, the ISO is finding there is still much to learn about how to model such resources in ISO systems. These modelling issues include managing ramp rates for chemical battery resources, identifying state of charge in the day-ahead market, and requiring load schedules to support a known state of charge for the award and dispatch of energy and ancillary services.

- *Ramping:* An issue for certain types of storage resources based on chemical batteries is that the charge and discharge rates change based on state of charge (SOC). These changes in rate can be caused by the underlying chemical process or the result of the governing control systems to protect battery life. This is significant for ISO-connected resources, because the charge and discharge rates equate to ramp speeds. Depending on the product, failing to deliver at the certified ramp rate can have a significant financial impact. As a result, some resources may prefer to reserve some stored energy capacity or headroom to ensure achieving a constant "fast" rate. Alternatively, they may need to certify at slower ramp rates to support the full range of discharge & charge. In either case, it reduces the financial value of the resource. Alternate modelling of ramp characteristics of such resources could possibly improve the financial efficacy of such resource types. Alternatively, the directional ramp could be limited when the resource is at an extreme state of charge. Note that certification of ramp for such resources may also need to be looked at more closely.
- *Load self-schedules required:* For the NGR non-REM option, the full range of ancillary services bids are not considered unless: 1) there is an offsetting energy schedule, or 2) there is a complimentary economic energy bid on the resource and an adequate state of charge (SOC) is available. As a result, NGR non-REM works best for a dedicated resource that can rely on market optimization to determine the timing and economics of whether it provides or consumes energy based on economic energy bids. For multiple purpose resources, this becomes very challenging when considering the resource may have a need for a particular level of energy storage at a definite time for its primary use (e.g., maintaining vehicle charge).
- *SOC in the day-ahead:* The day-ahead market uses a forecasted state of charge as a basis for bid awards. This forecast starts with a reading from two days before the trade date and is based on ISO awards for the day before the trade date. There may be little correlation between this forecasted amount and the actual SOC at the beginning of the trade date. This dynamic can result in awards where there is no capacity, or no awards where there is capacity. Both results create financial challenges for resource owners.

Possible Actions

5.2.3.1	Evaluate Energy Storage Modeling Improvements

4.5.2 Ancillary Services Certification Tests

Applies across all scenarios with the dynamic capacity variant.

The ancillary services (AS) certification test is the last step to prepare a resource for wholesale market AS delivery. Although the details depend upon the specific AS product, the certifications effectively follow the same process: (1) the resource owner requests a certification amount; (2) the ISO verbally dispatches the resource to that amount while measuring the delivery in real-time; (3) the ISO assigns a certified quantity to the resource (e.g., 1 MW of spinning reserves) assuming the resource meets certification requirements. Typically, conventional generator owners attempt to achieve the highest certification amount possible because doing so improves bidding flexibility and the alternative is to either leave generation out of the market or re-certify.

There are several issues with this concept of certification affecting DERs composed of sub-resources with dynamic capacity. The first is based on the desire to achieve a high certification value in the same way that conventional generators do:

- For PEV applications based on the storage capabilities of vehicles there is a logistical challenge. For an example, take for frequency regulation tests for such a resource. Before the test begins, the resource owner needs to dedicate their fleet of vehicles to the test, fully charging or discharging them depending on whether it is a regulation-up or down test. Once the test begins, they will need to discharge or charge the vehicles at their desired ramp for the duration of the test. This process will be logistically challenging, and take them out of their primary purpose for a significant amount of time. It is worth noting that they may not operate their resource in this way outside of a test, instead relying on vehicle usage and location forecasts to determine charging requirements and market capabilities.

- For DR applications that are weather dependent, the main issue is scheduling them on an appropriate day to achieve a reasonable result for the resource owner. If the weather is not conducive to a test (e.g., perhaps it is a particularly cold), re-tests will be necessary as the weather becomes more conducive to the maximum result.

A related issue affecting aggregations is the potential need for more frequent certification tests while the aggregation grows over time.

The other side of the coin in these cases has similar impacts: what, if any, process should be undertaken when there are fewer vehicles available, the colder months are approaching, or the aggregation is shrinking? Although re-certification may appear to be the best solution, it does not address the reality that a successful test may reflect very little on the actual capacity available on any specific day. Ultimately, this issue should be of greater concern to the ISO, because the certification test is intended to assure grid reliability: that if an ancillary service is procured from a resource that the resource can deliver it.

Possible Actions

5.2.3.2	Evaluate Certification Alternatives

4.5.3 Maximum Generation and Certified Quantities

Applies across all scenarios with the dynamic capacity variant.

At the ISO, resources are assigned attributes that define maximum generation (PMax) and certification quantities as described in the previous section. While these quantities may be changed, they are intended to be a reflection of a resource constant. These quantities do more than just limit the bid quantities in the market, they also act as an upper bound for other rules. For example, ISO operators can use an exceptional dispatch to drive a resource up to its PMax, irrespective of market bids. While that is a somewhat rare case, AS bidding requirements are more of a concern: day-ahead ancillary services awards below the certified quantity must be followed by real-time bids up to that quantity. In either case, this should not be an issue for a resource for which the maximum capacity is fairly fixed. For other resources with dynamic capacity – specifically weather-sensitive demand response and aggregations of vehicles in the VGI case – it will often be an issue because the ISO cannot assume that there is any excess capacity above the bid quantity.

This issue is somewhat addressed today through the ISO outage management system (i.e., SLIC); however, that system is not designed for daily – or even hourly – de-rates. This solution is also inapplicable for PDR because ISO rules only allow a full de-rate for PDR, taking the resource completely out of the market. For PDR resources that have significant variability, there may be too much for risk associated with this issue to bid them as ancillary services.

The most direct solution to these problems is to include a resource option in the Masterfile that treats bid quantities as a ceiling for the purposes of related rules.

Possible Actions

5.2.3.3	Introduce Dynamic Capacity Resource Aware Bidding Rules

4.6 Wholesale Distribution Access Tariff

Applies to dedicated facility, and behind the meter (exporting) scenarios.

Acquiring an interconnection agreement is a major part of the process for a non-PDR resource. For UDC-connected generation providing service to the ISO, this agreement falls under the Wholesale Distribution Access Tariff (WDAT)[12]. The WDAT itself is a tariff filed by each UDC with FERC. It contains all of the procedures, policies, and legal agreements necessary to interconnect a generator to the UDC's grid. Note that while the ISO requires this, the agreement itself is between the resource owner and the UDC with each agreement ultimately filed with FERC.

Completing a WDAT agreement can be complicated and time-consuming, particularly for storage-based resources. In one relevant project, the process of attaining a WDAT has already taken more than a year. There are many reasons that make this process challenging:

- When attaining a WDAT agreement, the resource owner must get active participation and permission from the UDC. This contrasts with PDR registration where LSEs and UDCs primary role is to validate the eligibility of service accounts.
- The existing WDATs and underlying processes were not written with storage resources in mind. Particularly, they do not account for bi-directional power needs beyond the concept of station power. As a result, the IOUs have little experience negotiating them for storage resources.
- When interconnecting an aggregation of like resources, each resource may need a WDAT negotiated for each sub-resource. Note that this is not an ISO requirement, but a UDC requirement.
- Each UDC has a unique WDAT, and therefore, a unique process for resource owners to follow.

As covered in Section 4.4.3, under some circumstances it may be possible to avoid the need for a WDAT agreement altogether when there is no net export of energy.

Any simplification or and standardize the WDAT process for resource owners would be a major advancement to help bring DERs online faster.

Possible Actions

5.2.5	Simplify and Standardize WDAT and Process for DER

[12] Rule 21 interconnections are not relevant because the ISO requires WDAT agreements for all NGRs.

4.7 Metering and Telemetry Challenges

Applies to all scenarios.

In 2012, the ISO initiated a stakeholder group to expand the options for metering and telemetry to reduce the cost through alternate technical means and/or relaxation of some technical and policy requirements. The motivation for this effort is that the existing rules were established primarily for large-scale dedicated resources, and as such are generally too costly for smaller DERs.

The main objectives to overcome the challenges presented by existing rules identified by the stakeholder group were:

- Increase the scenarios under which the Internet can provide connectivity for metering and telemetry, easing the requirement for use of dedicated leased lines, specifically the Energy Communications Network (ECN).
- Ease the restriction requiring that telemetry gateways be sited within the same sub-LAP as the telemetered resources.
- Ease the restriction allowing only resource owners to provide telemetry for resources owned by others.
- Establish a construct under which an aggregation of (non-PDR) sub-resources can be metered cost effectively without requiring individual ISO meters for each sub-resource comprising the aggregation.
- Enable ICCP as an alternative communication protocol for resource owners to employ for telemetry.

The ISO has made various proposals to support these objectives; however, it will be important that this effort continue to be a priority into 2014.

There are additional issues relevant to metering and telemetry:

- There is the question of whether telemetry can be relaxed in some cases that are required today. For example, the 10 MW requirement for resources to provide telemetry will likely keep PDRs below that threshold. This could result in many sub-10 MW resources totaling well over 10 MW without telemetry. If such a group of resources has no telemetry anyway, then perhaps relaxing telemetry for PDRs in general would make sense.
- There is no regulatory or policy framework for the ISO or the UDC sharing the same meter. This could reduce costs in some cases and greatly simplify shared purpose cases.
- Subtractive metering performed by either the ISO or UDC, and net metering scenarios could also help with the mixed-use cases, but NGR does not currently support this.

In particular, these last two items impact Scenario 3.1.3: Extra-Facility. Today solutions for that scenario require a UDC meter, and two ISO meters including subtractive metering by the ISO. The inability to share such meters combined with the fact that there is not an accepted standard practice for the ISO and UDCs to manage subtractive metering, makes each of these cases a custom solution.

In addition, there is a recurring issue where some potential resource owners may dismiss the inclusion of ISO metering and telemetry on their premises due to security concerns related to allowing external network traffic or circuits into their facilities. To some degree these issues can be solved by "pushing" such data to the ISO or a third party, given that the relevant parts of the stakeholder process on expanding metering and telemetry are implemented.

Possible Actions

5.2.6.1	Complete Phases 1 and 2 of the Expanding Metering and Telemetry Options Proposals
5.2.6.2	UDC subtractive and/or logical metering
5.2.6.3	ISO / UDC Meter Sharing
5.2.6.4	Standardize process for and access to RQMD
5.2.6.5	Evaluate Telemetry Requirements for PDRs

4.8 Aggregation Boundaries

Applies to all scenarios.

Limitations on aggregation makeup create challenges for developing DERs made up of multiple locations. These limitations are: (1) aggregations must contain locations from within a single sub-LAP; and, (2) aggregations must contain locations all served by the same entity (LSE). Both limitations affect PDRs today, while only the same sub-LAP limitation impacts NGRs.

An additional issue with sub-LAPs as defined today is that they do not relate to the local capacity areas (LCA). LCAs are used for resource adequacy and planning purposes by utilities, as well as for defining aggregator-managed demand response contracts (AMPs).

Figure 10 shows the current ISO sub-LAPs and a comparison with the local capacity areas used for utility resource procurement.

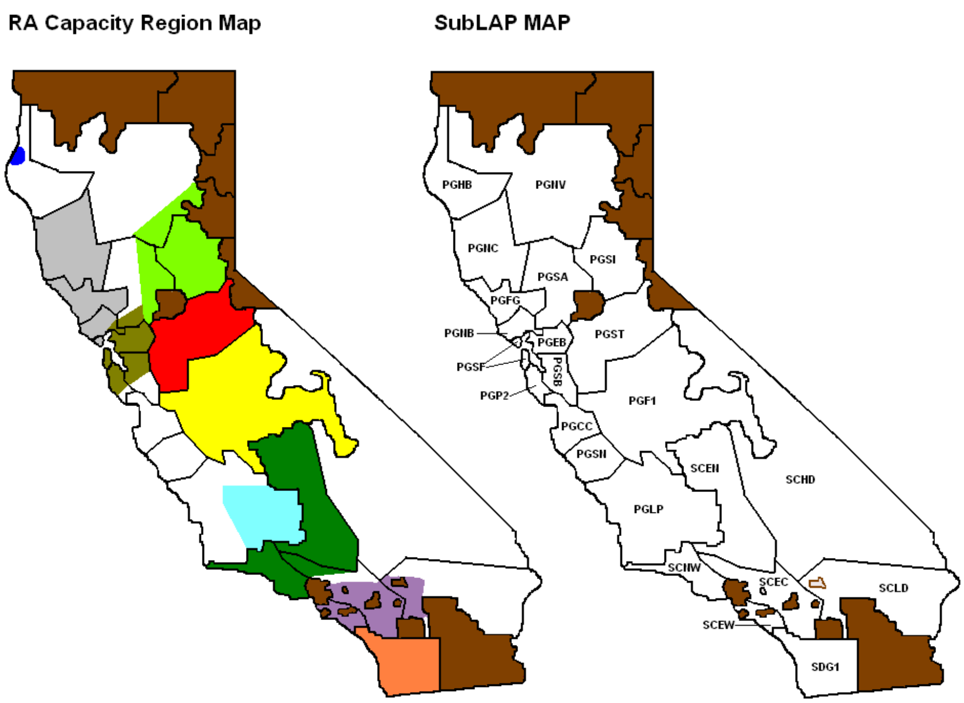

Figure 10: Local Capacity Areas and Sub-LAPs

There are challenges created by these aggregation limitations:

- It becomes more challenging for resource owners to build resources of sufficient size. For example, a resource owner with three 200 kW installations in the inner San Francisco Bay Area would have enough capacity for frequency regulation; however, unless these installations are all within 1 out of the 6 unique sub-LAPs in the area, then there is no wholesale market opportunity[13]. This becomes more challenging because resource owners cannot easily determine the sub-LAP for locations because there is no system nor defined process for getting this information.

- It becomes infeasible to integrate retail demand response programs into the wholesale market unless they are already segmented by sub-LAP and LSE. It follows that tariff-based utility-wide programs cannot be integrated in a meaningful way without significant changes. Today, if a utility did integrate a program that was not segmented appropriately, the utility would need to trigger the entire customer base when only a single PDR in a single sub-LAP received an award. This dynamic would unnecessarily dispatch customers and make it largely infeasible to bid cost-effectively.
- Aside from the challenges mentioned above, with this disconnect between sub-LAP and LCA, the utility cannot reasonably both support the wholesale market integration and target events in such programs to meet local needs.
- There is the possibility that sub-LAP boundaries can change over time, creating the potential of invalidating a resource and a subsequent loss in invested capital.

It is worth noting that while the impacts of a single sub-LAP and single LSE requirement are similar, providing solutions to these two issues are likely very different. One major aspect of the LSE issue is that LSEs are provided access to view awards for PDRs containing their customers as registered by a third party DRP. If aggregations were to commingle LSEs there would be no straightforward way to report awards to LSEs without sharing otherwise confidential information.

Possible Actions

5.2.2.3	Allow Resources to Span Sub-LAPs
5.2.2.4	Allow PDRs to Span LSEs
5.2.8	Sub-LAP Mapping System for Stakeholders

4.9 Demand Response Challenges

This section covers challenges unique to demand response in the ISO today, noting that DR issues are covered in many other parts of Section 4.

4.9.1 Baselines and Sub-metering

Applies to behind the meter (load only) scenario.

PDR performance is based on pseudo-generation quantities derived from whole-premises meter data using a baseline algorithm. This algorithm uses an average profile of the 10 previous similar non-award days with a day-of adjustment capped at 20%. This algorithm is acceptable for many end-use and premises configurations; however, there are many cases where the ultimate settlement quantities will diverge from actual performance. For example:

- *When operational schedules of the premises are not compatible with the ISO's single definition of similar days*: for example, a location that does not operate on Sundays and Mondays would have baselines that are skewed downwards for every day. The participant would therefore achieve

[13] Note that some suggest lowering resource minimums below the 100 kW for PDR energy and 500 kW for NGRs and ancillary services; however, that barrier is not addressed in this report aside from noting that as a bulk market operator, minimums are required and reasonable.

lower measured performance than actual performance. This particular issue may be improved by allowing a more flexible baseline approach that better suits the underlying locations, noting that the new RDRR resource type allows for the DRP to define alternate performance measurements with approval of the ISO. While the actual process for getting approval for the ISO is not clear at this time, it seems reasonable that this would be applied to PDRs as well.

- *When other loads behind the whole-premises meter are variable or when the rest of the premises dwarfs the size of the curtailable load*: in these cases, valuable DR cannot equitably participate in the ISO. A solution to this issue could be to enable sub-metering on the end-uses that provide the load shed within a facility.

Possible Actions

5.2.2.5	PDR Performance Measurement Options

4.9.2 Inflexibility of Demand Response System and Processes

Applies to behind the meter (load only) scenario.

The Demand Response System (DRS) is the system of record for demand response locations registered at the ISO. The DRS records the relationship between the location, LSE and DRP; it also supports the validation process for all relevant parties. This system and the policies around it create several challenges for the integration of DR in the ISO market.

The validation process – whereby each party has the opportunity to identify potential registration issues – creates a high level of complexity in the overall registration process making it difficult to integrate retail programs into PDR without costly management infrastructure. There are two specific, related issues:

- *All or nothing registrations:* If any party rejects a location from a PDR registration, the entire registration is made invalid. For example, if 9 of 10 locations are OK, but 1 has an incorrect service account number, then the entire registration must be re-created, and the entire validation process starts again.
- *Potential for registration gaps when changing a PDR makeup:* Changing a PDR requires terminating the current registration and creating a new one. For example, in a case where a DRP needs to add a single location to a PDR, the DRP would need to terminate the existing registration and create a new registration including all existing locations in addition to the new location. If that new location is rejected by one of the parties during the validation process, then the entire registration is invalidated. To restore the previous registration, the DRP must re-register it, restarting the entire validation process again for a group of locations that were already deemed valid. There is a very real risk that the resource will therefore not be operational by the time the initial registration becomes ineffective. One solution to this problem would be to allow the initial registration to persist until superseded by the new valid registration; another solution would be to allow the previous registration to be reinstated. This is a critical issue for the integration of retail programs into PDR.

Another challenge is in the case of registering and managing large numbers of resources and/or resources made up of large numbers of locations. This would be very challenging today given the lack of registration APIs for the DRS. It will be critical that the ISO implement these APIs or some alternative; however, a new approach to defining PDRs is likely necessary when managing very large (i.e., mass market) resources.

Possible Actions

5.2.2.6	PDR Registration Improvements
5.2.2.7	Evaluate Mass Market PDR Improvements
5.2.2.8	Improve DRS Integration Capabilities

4.10 Inability to Test New Technologies for Regulation

Applies to all scenarios that support frequency regulation.

A great deal of innovation on technology and business models is occurring around the notion of delivering frequency regulation from DERs. For example, this is the primary focus of many DOD projects in California. Unlike other products at the ISO that require response no more frequently than every 5 minutes, frequency regulation relies heavily on the 4-second Automatic Generation Control (AGC) signal sent from the ISO EMS.

The actual AGC signal that a resource will observe in the ISO market is different from what occurs in other markets. To be clear, this is not an issue of protocol and data points, but of the behavior of that signal when controlling a resource particularly interleaved with the resource's charge state. This actual signal is critical to determining if a technology will work – and to understand the underlying costs and wear and tear imposed by that signal.

The challenge for innovators in this space – including vehicle OEMs, battery and storage manufacturers is that the only way to observe the actual signal is to take on the expense and effort to fully integrate with the ISO. This can be somewhat mitigated through an ISO Pilot; however, such a solution would only support a single vendor and is not a scalable approach available to all innovators.

All in all, this creates a major challenge to new entrants and creates a significant risk for those who navigate the challenge.

It should be noted that the market simulation capabilities at the ISO do not support any actual AGC (or telemetry) connectivity. A solution to add this capability to market simulations could be of help, although overall market simulations are of limited value to new entrants outside of system integration opportunities. A more comprehensive solution would be a lab environment, with a persistent grid interconnection to enable live testing against the market and AGC.

Possible Actions

5.2.9	Introduce Lab Environment for Regulation

5 Actions

This section enumerates actions to mitigate or resolve items covered in Section 4. Each action includes the barriers and challenges covered in the previous section.

The intention has been to list reasonable actions to the issues at hand, though this report does not cover the universe of possible actions: The purpose of this paper to identify barriers and challenges to wholesale integration, not to delve into the question of whether wholesale integration is the best application of certain types of DERs to best meet California's needs.

Each action in the following sections includes a summary of the action, the items addressed and the agency or agencies that would likely need take the lead. While some of the actions are straightforward (e.g., implement dynamic capacity aware bidding rules), others identify a need and suggest an evaluation of various ways forward.

In addition, each action is scored on a scale from 1 – 3 for level of effort and impact. In all cases in this report, a higher number indicates a better score. For example, a score of 3 implies highest impact and least effort. Section 5.1 details the scoring methodology.

Finally, this section concludes with an analysis of the actions based on the scoring and ultimately recommendations for moving forward.

5.1 Scoring Criteria

To assist in prioritization, each action received an overall score for impact and effort from a range of 1 to 3 with a higher number indicating a better score across both measures. This is not intended to be an elaborate scoring mechanism but an initial effort to provide some guidance for determining priorities for regulatory engagement and project planning.

Score	**1**	**2**	**3**
Impact	Lower impact	More impact	Most impact
Effort	Most effort	Moderate effort	Least effort

The overall scores were calculated from a simple average of assigned sub-scores (see Appendix A for specific scores).

The impact criteria are as follows:

- Will it improve access to different types of resources / ISO models?
- Will this increase the amount of distributed energy resources participating in the ISO market?
- Does it address the 'duck' problem?
- Does it address more than one issue?
- Does it facilitate emerging technology?

The effort criteria are as follows:

- Will it require a regulatory change?
- Can it be implemented by the ISO alone?
- Does it require an ISO stakeholder process or CPUC regulatory proceeding?
- Are information system changes required?
- Is there some consensus on the approach?

The individual scores are based on direct experience, interactions with other stakeholders and discussions with the ISO and other parties. The scoring and ultimate ranking is not the result of deep analyses of impact and effort, but is intended to give a rough cut to inform next steps. This is a useful starting point. We acknowledge that deeper evaluation of both the scores and weights is a reasonable next step.

5.2 Possible Actions

The actions in the following sections are listed in Table 3: Actions and Scoring.

		Impact	Effort
5.2.1	Improve Revenue Equality and Opportunity	2.6	1.4
5.2.2.1	Enhance PDR for Frequency Regulation	2.2	2.4
5.2.2.2	Add Capacity-only Frequency Regulation	2.2	2.6
5.2.2.3	Allow Resources to Span Sub-LAPs	2.2	2.8
5.2.2.4	Allow PDRs to Span LSEs	1.8	1.2
5.2.2.5	PDR Performance Measurement Options	1.8	1.2
5.2.2.6	PDR Registration Improvements	1.4	2.6
5.2.2.7	Evaluate Mass Market PDR Improvements	1.6	1.2
5.2.2.8	Improve DRS Integration Capabilities	1.8	2.6
5.2.3.1	Evaluate Energy Storage Modeling Improvements	2.0	2.4
5.2.3.2	Evaluate Certification Alternatives	2.2	2.6
5.2.3.3	Introduce Dynamic Capacity Resource Aware Bidding Rules	2.2	2.2
5.2.4.1	Enhance Documentation of PDR Integration Process	1.4	3.0
5.2.4.2	Combine PLA and PGA for NGR Implementation	1.6	2.8
5.2.4.3	Evaluate Streamlining NRI for Non-exporting NGRs	2.0	1.8
5.2.5	Simplify and Standardize WDAT and Process for DER	2.2	1.6
5.2.6.1	Complete Phases 1 and 2 of the Expanding Metering and Telemetry Options Proposals	2.6	2.4
5.2.6.2	UDC subtractive and/or logical metering	2.2	1.4
5.2.6.3	ISO / UDC Meter Sharing	1.4	1.2
5.2.6.4	Standardize process for and access to RQMD	1.6	2.2
5.2.6.5	Evaluate Telemetry Requirements for PDRs	1.6	2.4
5.2.7	Establish Rules and Pro-forma Agreements for DRP / LSE Cooperation	2.0	2.0
5.2.8	Sub-LAP Mapping System for Stakeholders	1.8	2.4
5.2.9	Introduce Lab Environment for Regulation	1.8	2.8

Table 3: Actions and Scoring

5.2.1 Improve Revenue Equality and Opportunity

Actions: There are many activities currently under way to address the revenue inequality and opportunities for DER, especially for those that supply demand response. This is of particular importance, because the number one barrier to entry for demand response in ISO, after Electric Rule 24 is completed, will be the lack of revenues beyond that available in the wholesale spot energy market. It is beyond the scope of this paper to identify the specific means to that end; however, the following items address this issue, some more directly than others:

- In developing a forward capacity procurement framework to fill the gap between the short-term RA process and the LTPP, ensure that there are options compatible with DR capabilities.
- Completion of FRACMOO development to enable DER to participate in RA contracts with wholesale integration requirements. May require further refinements to use-limited resource accommodations to attract a deeper pool of DERs.
- ISO stakeholder effort to define the must-offer obligation for demand response and other use limited resources to qualify for system and local resource adequacy.
- SCE's all-source procurement and living pilot provides another revenue opportunity for DERs
- Consider a multi-year competitive auction mechanism for demand response and DER aggregations that provide capabilities to specifically address the "duck curve" challenges.

Addresses: 4.1 Lack of Revenue Equality / Opportunity

Agencies: ISO, CPUC, FERC

Impact: 2.6, *Effort:* 1.4

5.2.2 New Products and Product Enhancements

5.2.2.1 Enhance PDR for Frequency Regulation

Action: Introduce concepts of the NGR model to the PDR model to support frequency regulation and energy limits in the context of demand response.

Adding frequency regulation to PDR is contemplated in the stakeholder catalog as a "Combined Demand Response Product" or "PDR-NGR", enabling behind-the-meter end uses to supply frequency regulation in addition to spinning reserves without the requirement of full interconnection. This is particularly useful for electricity storage and thermal storage which can participate in frequency regulation in both charge-only and charge/discharge scenarios. Although this action would not remove the requirements on export, it would dramatically reduce implementation time and create more revenue potential for participation.

Addresses: 4.1 Lack of Revenue Equality / Opportunity, 4.2 Behind the Meter

Agencies: ISO with FERC approval

Impact: 2.2, *Effort:* 2.4

5.2.2.2 Add Capacity-only Frequency Regulation

Action: Implement systems and policy for a capacity-only frequency regulation option, eliminating the wholesale energy settlement.

A capacity-only frequency regulation product would enable behind-the-meter service while eliminating the issues around mixing wholesale and retail energy. Such a product would be based on the premise that, overall, eligible resources would be controlled towards net-energy neutrality and therefore would not require energy settlement in the wholesale market. This could simplify the WDAT process, and perhaps eliminate the requirement altogether in some cases. By relegating the energy financial settlement to the local utility, issues of double-procurement and payment are eliminated partially addressing the lack of revenue equality and opportunity barrier. Resources participating in this product would likely not need ISO metering because all necessary information, including pay for performance, would be supplied from ISO-approved telemetry solutions. This solution would likely only apply for NGR-REM resources today though other products in the future, including PDR and/or NGR demand response.

Addresses: 4.1 Lack of Revenue Equality / Opportunity, 4.2 Behind the Meter , 4.6 Wholesale Distribution Access Tariff

Agencies: ISO with FERC approval

Impact: 2.6, *Effort:* 2.6

5.2.2.3 Allow Resources to Span Sub-LAPs

Action: Enable PDRs and NGRs that apply to the Default-LAP instead of constraining them within a sub-LAP.

Allowing PDRs and NGRs to be composed of sub-resources that cross sub-LAPs boundaries will ease the implementation of aggregations of smaller resources and reduce the friction between utility-wide rate-based programs and the wholesale market. In the former case, it is expected that much capacity will be kept out of the market by DRPs until there is enough within a single sub-LAP to meet the minimum resource requirements. It would be reasonable to allow resources to span sub-LAPs, if the locations themselves are below some size threshold. Note that this action could be addressed as two separate items, treating PDRs and NGRs separately.

Addresses: 4.8 Aggregation Boundaries

Agencies: ISO

Impact: 2.2, *Effort:* 2.8

5.2.2.4 Allow PDRs to Span LSEs

Action: Enable PDRs to consist of locations from multiple LSEs.

Allowing PDRs to be composed of locations from multiple LSEs will ease the implementation of aggregations of smaller resources and the wholesale market. This may become an issue for NGRs as rules for a behind-the-meter frequency regulation product are defined. Enablement includes some complexity due to existing rules that provide market award information to LSEs and the continuing potential for default load adjustments (DLA) to be made to an LSEs load schedule. If such rules continue, then this would imply SQMD aggregations by LSE within a PDR as well as award disaggregation by the ISO, the latter of which may be challenging or beyond the scope of the ISO. Alternatively, if the DLA were in all cases eliminated, and award information were provided to the LSE through some other means (e.g., a responsibility of the DRP), then this action might become more tenable.

Addresses: 4.8 Aggregation Boundaries

Agencies: ISO, FERC

Impact: 1.8, *Effort:* 1.2

5.2.2.5 PDR Performance Measurement Options

Action: Investigate alternate baseline methodologies, including custom operational schedules, reliance on sub-metered data, and removing the cap on day-of adjustments

The existing "one size fits all" approach to performance measurement for demand response resources does not fairly represent the delivery of load shed in many cases. For example, a DER might provide a demonstrable drop that can be detected in the real time; however, it becomes lost when commingled with the average profile of an entire facility. This issue can be exacerbated if the operational schedule of the facility does not match the day-type definitions at the ISO. This issue cuts across wholesale and retail programs, and in fact, the 10-in-10 baseline is essentially the standard for retail programs in California. Improving this situation will not be trivial, but this type of baseline does keep demand response from participating today due to lack of revenues in the retail utility context. There is every reason to believe this will spill over into wholesale participation impact. In some cases, alternative baselines may be the answer while in other cases more direct metering of the end-uses may be the answer. In any case, it is our expectation that baselines and performance measurement will need to be aligned with retail programs.

Addresses: 4.9.1 Baselines and Sub-metering

Agencies: ISO, FERC, CPUC

Impact: 1.8, *Effort:* 1.2

5.2.2.6 PDR Registration Improvements

Action: Enhance the PDR registration process to avoid registration gaps when updating registrations.

The design of the PDR registration process creates a situation that can leave PDR resources with registration gaps due to frequent changes in the sub-resources of the aggregation, keeping them out of the market as described in Section 4.9.2. This will be primarily an issue for the direct participation of utility-based programs as well as any aggregation that changes frequently. This problem can be fixed by no longer requiring the termination of a registration before creating a new one to supplant it, and ultimately auto-terminating the previous registration if and when the new one goes into effect.

Addresses: 4.9.2 Inflexibility of Demand Response System

Agencies: ISO, FERC

Impact: 1.4, *Effort:* 2.6

5.2.2.7 Evaluate Mass Market PDR Improvements

Action: Enhance the PDR registration process to better suit PDRs made up of mass market locations.

The requirement to include each service account location in every PDR registration within the DRS will become an administrative chore for PDRs made of a very large number of locations. Other solutions could be considered, for example, parallel sub-registrations or pseudo-locations that map to an aggregation of customers managed by the IOU or a certified third party outside of the Demand Response System.

Addresses: 4.9.2 Inflexibility of Demand Response System and Processes

Agencies: ISO, CPUC

Impact: 1.6, *Effort:* 1.2

5.2.2.8 Improve DRS Integration Capabilities

Action: Improve DRS integration capabilities, including the possibility of adding comprehensive APIs or automated file transfer mechanisms to support integration with existing enterprise systems of record.

IOUs and Third-Party DRPs will not be using the DRS to manage their registrations. They will typically have their own source systems for tracking portfolios of DR. Without integration capabilities in the DRS, parties will need to manually duplicate data from their systems of record into the DRS. It is infeasible to manage more than a handful of PDRs or locations this way. The issue could be mitigated with actions described in Section 5.2.2.7 related to mass market DR by avoiding some cases where high volumes of registration activity are required; however, that is a distinct issue. Such integration capabilities could include APIs with a complete data model for the underlying content, or alternatively, could support the exchange of a document with a well-defined format. Regardless, such capabilities should include all registration activities, meter data upload, and baseline and performance data download operations.

Addresses: 4.9.2 Inflexibility of Demand Response System

Impact: 1.4, *Effort:* 2.6

5.2.3 Improve Wholesale DER Fit

5.2.3.1 Evaluate Energy Storage Modeling Improvements

Action: Evaluate lessons learned, identify and evaluate gaps between the existing NGR model and practical storage technologies.

Several issues have been raised during the implementation and operations of new NGR resources both for dedicated resources as well as for PEV fleet charging as described in Section 4.5. Some of these issues point to gaps between the NGR model and the operation of energy storage technologies. This action could include:

- Evaluate whether other solutions exist to better model storage at extremes of SOC.
- Evaluate solution to the day-ahead SOC issue.
- Evaluate solution to energy procurement requirement for NGR Non-REM resources.

Addresses: 4.5.1 Storage Modeling

Agencies: ISO, FERC

Impact: 2.0, *Effort:* 2.4

5.2.3.2 Evaluate Certification Alternatives

Action: Identify and evaluate alternatives to the existing AS certification process for DER.

Ancillary services certification testing improves the reliability of the grid by ensuring that resources can provide the ancillary services when awarded. This is particularly important, because, different from energy awards, ancillary services awards are for capacity and often do not result in the delivery of any energy. This certification process has proven successful in ensuring the objective of reliability when it comes to conventional generation, but it does not support that objective in the case of dynamic capacity resources for which actual capacity availability may vary greatly. This has not been a problem to date given the low penetration of such resources; however, more and more such resources will be providing ancillary services in the future. Finding a means to certify such resources fairly while protecting the reliability of the grid is an important unsolved problem.

Addresses: 4.5.2 Ancillary Services Certification

Agencies: ISO, FERC

Impact: 2.2, *Effort:* 2.6

5.2.3.3 Introduce Dynamic Capacity Resource Aware Bidding Rules

Action: Introduce dynamic capacity resource aware bidding rules and options

The obligations to be available up to a fixed maximum generation or load response capacity for exceptional dispatch or when awarded ancillary services may be sensible for conventional generation; however, these rules introduce significant risks to owners of resources made up of dynamic capacity resources where actual available capacity can vary greatly. In these cases, the bid-in capacity should be considered an absolute maximum. Without this or some other solution, such resource owners may need to significantly under-certify their resources, resulting in capacity made available to the grid at lower potential revenues.

Note that the ISO has a feature planned for release in 2014 to constrain energy and AS procurement to an hourly limit; this may ease this challenge for ancillary services; however, it appears exceptional dispatch may still be an issue.

Addresses: 4.5.3 Maximum Generation and Certified Quantities

Agencies: ISO, FERC

Impact: 2.2, *Effort:* 2.2

5.2.4 Enhancements to NRI Process

5.2.4.1 Enhance Documentation of PDR Integration Process

Action: Enhance the documentation of PDR implementation to be on par with the NRI process documentation.

Enhancing the documentation on all aspects of PDR implementation would better facilitate the integration of such resources in the future. This will be particularly important because PDR is expected to begin to get much more use in 2014. Such documentation would combine all steps of PDR integration, for example, necessary agreements, registration steps, custom-PDRs, and telemetry. It is likely that completing this documentation process would provide insights into process improvements as well.

Addresses: 4.4.1 NRI Process for PDR

Agencies: ISO

Impact: 1.6, *Effort:* 3.0

5.2.4.2 Combine PLA and PGA for NGR Implementation

Action: Create a combined PLA and PGA for NGR resource owners

Currently, NGR resource owners must execute both a Participating Load Agreement (PLA) and Participating Generation Agreement (PGA) with the ISO. Creating a single agreement that combines necessary elements of the PLA and PGA will simplify the implementation of NGRs, ultimately reducing the effort required by resource owners and reducing legal fees.

Addresses: 4.4.2 Participating Load and Generation Agreements

Agencies: ISO, FERC

Impact: 1.8, *Effort:* 2.8

5.2.4.3 Evaluate Streamlining NRI for Non-exporting NGRs

Action: Identify and evaluate opportunities to streamline the NRI for non-exporting NGRs, in particular the evaluating the requirement for the WDAT.

Currently, NGRs that do not export across the whole premises meter require a WDAT Agreement. Such resources could potentially be treated more like demand response where such an agreement is not necessary. Evaluating whether the WDAT can be avoided, and if there are other opportunities for streamlining, could reduce the implementation time and cost of NGR projects.

Addresses: 4.4.3 Non-exporting NGRs Require Interconnection Agreement

Agencies: ISO, FERC

Impact: 2.0, *Effort:* 1.8

5.2.5 Simplify and Standardize WDAT and Process for DER

Action: Begin a joint stakeholder process with the goal of simplifying and standardizing the WDAT and associated processes for DER

Navigating and ultimately attaining a WDAT Agreement for a new NGR implementation is challenging for resource owners. There would be a great benefit in a simplified process standardized across and all three IOUs. One way to achieve this would be to launch a stakeholder process with these goals in mind. Issues to be covered in such a process might include:

- Establish standards for treatment of bi-directional energy storage
- Evaluate if WDAT is required for non-exporting NGRs
- Establish standards for how to treat DER aggregations
- Standardize WDAT interconnection processes across all IOUs

Addresses: 4.6 Wholesale Distribution Access Tariff

Agencies: IOUs, FERC, ISO, CPUC

Impact: 2.2, *Effort:* 1.6

5.2.6 Metering and Telemetry

5.2.6.1 Complete Phases 1 and 2 of the Expanding Metering and Telemetry Options Proposals

Action: Complete Phases 1 and 2 of the Expanding Metering and Telemetry Options proposals

In late 2012, the ISO began a stakeholder process to explore additional options to supplying metering and telemetry. The main impetus for this effort was to reduce the high costs for these critical implementation pieces, with the greatest benefit being for smaller resources for which the high costs become barriers. The ISO has moved beyond the original stakeholder process and has made several proposals.

Phase 1 includes the following proposals:

- Use of the Internet for telemetry and ISO metered entity (ISOME)[14] meter data bridging to the ISO ECN
- Use of the Internet for telemetry and meter data transport directly to the ISO
- Expand the use of inter-control center communications protocol (ICCP) as an allowable option for RIG Aggregators (telemetry only)
- Expand the ability for resources to submit settlement quality meter data (SQMD)

Phase 2 includes:

- Use of data concentrators to provide distributed energy resource aggregation, data concentration and control signal disaggregation services

It is beyond the scope of this document to dive into the details of these proposals; however, the successful implementation of each of these proposals will have an immediate positive impact on new DERs.

Addresses: 4.7 Metering and Telemetry Challenges

Agencies: ISO, FERC

Impact: 2.6, *Effort:* 2.4

5.2.6.2 UDC subtractive and/or logical metering

Action: Evaluate and determine a regulatory and policy framework under which the IOU will perform subtractive and/or logical metering in support of wholesale behind-the-meter operations.

Placing non-demand response resources behind a whole-premises meter creates several challenges identified in Section 4.2. In many cases, these challenges could be overcome with subtractive metering performed by the IOU. This would net out any wholesale activity from retail consideration. Such subtractive metering would require either access to the ISO meter or ISO meter data retrieval, a second sub-meter for the IOU, or a third party with access to both meters providing a service.

Addresses: 4.2 Behind the Meter , 4.7 Metering and Telemetry Challenges

Agencies: CPUC, IOUs

Impact: 2.2, *Effort:* 1.4

5.2.6.3 ISO / UDC Meter Sharing

Action: Evaluate the value of and, if necessary, develop a regulatory and policy framework under which the ISO and UDC can share meter data.

In some cases, particularly those described in Scenario 3.1.3 Extra-Facility, the ISO and UDC are installing meters in parallel that are metering a single facility or resource. Metering hardware and installation costs can be reduced if a single meter were used and either shared between both the ISO and UDC or, more likely, the meter data were shared from one party to another. Note that other solutions could also be applied here. For example, one of the proposals for expanding metering and telemetry options is to allow for submission of meter data in more cases.

Addresses: 4.7 Metering and Telemetry Challenges

[14] All participating loads and generators (i.e., all resource types except PDR) require directly-polled ISO metering.

Agencies: ISO, FERC, CPUC, IOUs

Impact: 1.4, *Effort:* 1.2

5.2.6.4 Standardize process for and access to RQMD

Action: Identify clear roles, quality requirements, timing, and costs for supplying RQMD in Electric Rule 24

The timely delivery of Settlement Quality Meter Data to the ISO is dependent on the retrieval of meter data from the relevant IOU. The timelines for retrieving this data as well as the quality of that data are key issues for Demand Response Providers; codifying the roles, requirements and timing is an important aspect of implementing Rule 24.

Agencies: CPUC, IOUs

Addresses: 4.3.2 Timely Access to Meter Data

Impact: 1.6, *Effort:* 2.2

5.2.6.5 Evaluate Telemetry Requirements for PDRs

Action: Evaluate the necessity of telemetry for energy-only PDRs.

All PDRs over 10 MW in size require telemetry. This is cost prohibitive for PDRs made of many locations; so much so that resource owners will avoid defining PDRs of that size. This will therefore lead to many sub-10 MW PDRs, all without telemetry instead of one larger PDR. Considering this, it may make sense for the ISO to eliminate the 10 MW requirement, at least for PDRs that are composed of many locations.

Addresses: 4.7 Metering and Telemetry Challenges

Agencies: ISO, FERC

Impact: 1.6, *Effort:* 2.4

5.2.7 Establish Rules and Pro-forma Agreements for DRP / LSE Cooperation

Action: Define rules that require Energy Service Providers (ESPs) to register as LSEs in the ISO DRS and develop standardized DRP/LSE Agreements.

The design of PDR expressly considered the rights of the customer to choose a DRP; however, the existing rules and systems create barriers for DRPs. The first, simpler issue, is that LSEs are not required to register in the DRS and there is no clear process by which a separate party can motivate this registration. The second issue is more complicated. The requirement placed on the DRP by the ISO to have an agreement with the LSE may be a blocker in many cases. The existence of standardized "pro-forma" agreements, explicitly made the requirement by the ISO and supported by the CPUC, could provide a solution while supporting the intention of customer rights.

Addresses: 4.3.1 DRP / LSE Contract Requirement

Agencies: CPUC, ISO

Impact: 2.0, *Effort:* 2.0

5.2.8 Sub-LAP Mapping System for Stakeholders

Action: Implement a system or service for resource owners to determine the sub-LAPs in which specific locations are electrically sited.

Resources made up of aggregations cannot cross sub-LAP boundaries; however, resource owners and prospective owners cannot easily determine where these boundaries are nor in which sub-LAP a particular site lies. Note that this would not be as much of an issue if DLAP-wide PDRs and NGRs were supported as described in Section 5.2.2.3. Resource owners need to understand these constraints before investing time and money recruiting customers and/or siting potential facilities. The lack of a clear system or process for determining Sub-LAP creates a challenge. Given that this stems from an ISO requirement, it follows that the ISO implement or oversee a solution although the IOUs will likely need to assist as well

Addresses: 4.8 Aggregation Boundaries

Agencies: ISO, CEC, CPUC, IOUs

Impact: 1.8, *Effort:* 2.4

5.2.9 Introduce Lab Environment for Regulation

Action: Implement a lab environment, or other suitable solution, to enable technology companies and perspective resource owners to test their systems against the ISO AGC signal without requiring a full interconnection or one-off pilots.

Innovation on technology and business models is occurring around the notion of delivering frequency regulation from DERs; however, the only real test of such technologies can come after a full interconnection with the ISO. This requires a significant investment in time from both the ISO and the stakeholder.

Addresses: 4.10 Inability to Test New Technologies for Regulation.

Agencies: ISO, FERC

Impact: 1.8, *Effort:* 2.8

5.3 Analysis

The following scatter chart plots the actions by impact and effort using the overall scores.

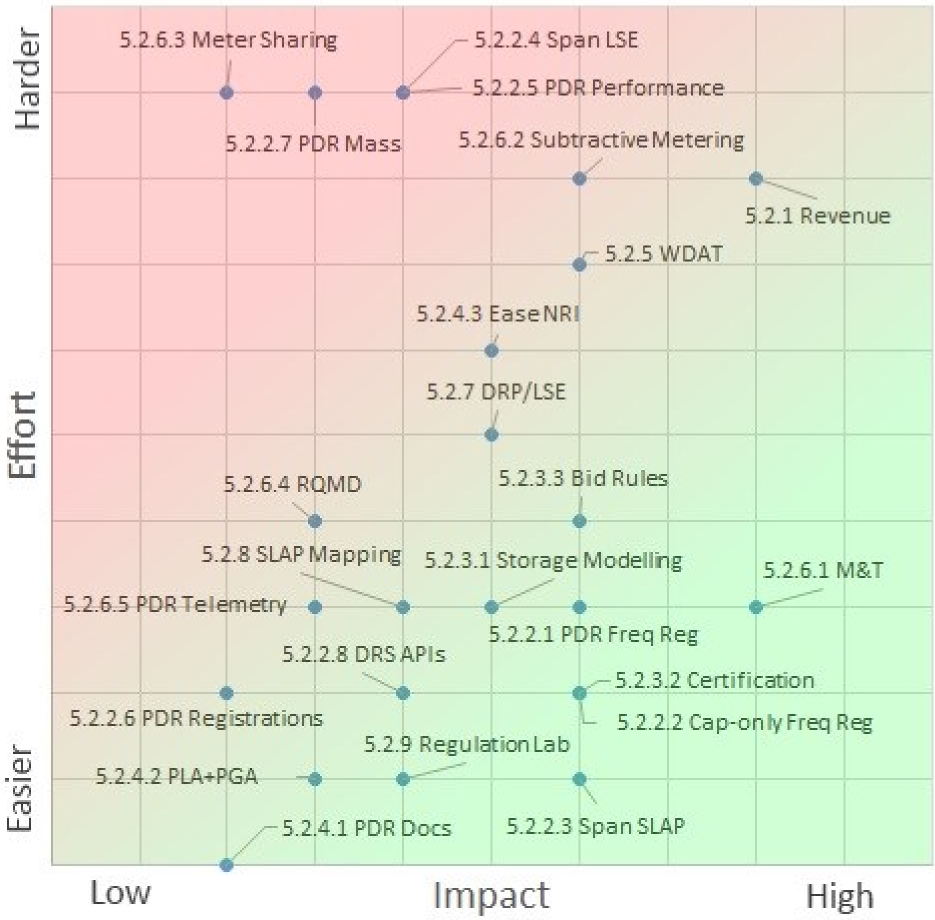

Figure 11: Impact and Effort

This chart is useful to visualize the areas of effort and impact. The coloring from green to red can be helpful to look for so-called “low hanging fruit”; however, this is a limited way to approach the problem particularly due to a lack of trivial actions with high impact. A more useful way to look at this information is to order by impact. Table 4: Barriers and Actions provides a summary of the actions and barriers prioritized by impact, with similar items grouped together.

Barrier	Implications and Actions	Agencies	Impact	Effort
4.1 Lack of revenue opportunity for DER	Without longer-term contracts / capacity payments, DERs will be limited in market participation 5.2.1 Improve revenue opportunity and equality	ISO CPUC	2.6	1.4
4.7 Expense and complexity of ISO metering and telemetry	Too expensive for DER; blocks innovative resource types and business models. 5.2.6.1 Complete Phases 1&2 of Expanding M&T Process	ISO	2.6	2.4
4.8 Sub-LAP and LSE Aggregation Boundaries	Barrier to tariff-based DR and, in general, integration of DER portfolios 5.2.2.3 Allow resources to span Sub-LAPs (2.2 / 2.8) 5.2.2.4 Allow PDRs to span LSEs (1.8 / 1.2)	ISO	2.2	2.8
4.5 Dynamic capacity challenges	AS certification tests for DERs that provide dynamic capacity due to shared use or weather sensitivity are challenging for resource owners to perform; such tests do not ensure grid reliability. Some bidding rules for such resources create financial risk and will lessen participation. 5.2.3.2 Evaluate certification alternatives 5.2.3.3 Introduce variable-capacity resource bid rules (2.2 / 2.2)	ISO	2.2	2.6
4.2 Limited support for shared-purpose DER	Forces many microgrid and VGI projects to follow full interconnection for non-exporting resources; requiring WDAT and complex process. 5.2.2.1 Enhance PDR for frequency regulation (2.2 / 2.4) 5.2.2.2 Option for capacity-only frequency regulation (2.2 / 2.6) 5.2.6.2 UDC subtractive and/or logical metering (2.2 / 1.4)	ISO CPUC IOUs	2.2	2.4
4.6 WDAT process costly with unclear time frames	Complexity of navigating WDAT agreements for bi-directional resources is complex with many unknowns; keeps potential owners from engaging. 5.2.5 Simplify and standardize WDAT process for DER	IOUs CPUC	2.2	1.6
4.5.1 Storage modelling mismatches	Potential for reduced capacity and revenues for LESR owners, including VGI scenarios; reduces cost effectiveness. 5.2.3.1 Evaluate energy storage modelling improvements	ISO	2.0	2.4
4.3.1 LSE cooperation required for DRP participation	Innovative DRPs blocked from entry in market due to an effective requirement of permission from LSEs, contrary to the intention of Electric Rule 24. 5.2.7 Establish rules and pro-forma agreements for DRP/LSE cooperation	CPUC ISO	2.0	2.0
4.4.3 Non-exporting NGRs require full interconnection	Bi-directional NGRs that do not export across utility meter could be treated like DR and potentially avoiding WDAT, getting resources into market more quickly. 5.2.4.3 Evaluate streamlining NRI for non-exporting NGR	ISO	2.0	1.8

4.9.2 DR registration challenges	The administrative costs for retail DR programs in general, and mass market programs in particular will be high to manage within the DRS. 5.2.2.8 Improve DRS integration capabilities (1.8 / 2.6) 5.2.2.7 Evaluate mass market improvements to PDR (1.6 / 1.2) 5.2.2.6 Other PDR registration improvements (CPUC, 1.4 / 2.6)	ISO	1.8	2.6
4.10 PEV OEMs and other providers must fully interconnect to test for frequency regulation	Requires full interconnection, expense, and multi-year effort to determine efficacy and value of technology against EMS AGC signal. 5.2.9 Introduce lab environment for regulation	ISO	1.8	2.8
4.8 Determining Sub-LAP membership	Actual mapping from address to Sub-LAP is not available to prospective participants; slowing down and creating uncertainty around resource composition. 5.2.8 Sub-LAP mapping system for stakeholders	ISO	1.8	2.4
4.9.1 PDR measurement incorrectly computes performance for certain types of resources	PDR baselines are only effective for sites with stable load profiles and certain operational schedules; this will keep significant DR out of the wholesale market. 5.2.2.5 PDR performance measurement options	ISO	1.8	1.2
4.4.2 PLA and PGA are both required for NGRs	Combining these agreements could simplify a complex process. 5.2.4.2 Combing PLA and PGA for NGR Implementation	ISO	1.6	2.8
4.7 Telemetry for large aggregations providing energy is cost prohibitive and ineffective	Telemetry is required for energy PDRs > 10 MW; PDRs of many locations will be held below 10 MW 5.2.6.5 Evaluate telemetry requirements for PDRs	ISO	1.6	2.4
4.3.2 RQMD will be challenging for DRPs to collect in a timely manner	ISO metering requirements and IOU metering processes are not aligned; significant settlement delays and risk will exist with standardized RQMD process. 5.2.6.4 Standardize processes and access to RQMD	CPUC IOUs	1.6	2.2
4.4.1 Process for integrating PDR beyond simple case challenging to navigate	Beyond the pre-defined PDR for energy only, the process for PDR is not well documented; creates burden on new entrants and ISO to support 5.2.4.1 Enhance documentation of PDR integration process	ISO	1.4	3.0
4.7 ISO and UDC may require duplicative metering	In some cases ISO and UDC meters are run in parallel; increasing installation and ongoing cost 5.2.6.3 ISO/UDC Meter Sharing	ISO IOUs CPUC	1.4	1.2

Table 4: Barriers and Actions

This table gives a better view of which actions will make the most impact. In particular, we can see all items that have an impact rating above 2, which we identify as being key areas for emphasis and focus moving forward. Noting that we believe that all of the items identified should be researched further to determine impact and effort.

Using this as a basis for further analysis, we believe a reasonable next step would be to begin a discussion with the lead parties in these actions – and other stakeholders when beneficial – to dive into details of feasibility, impact, and effort. Such a focused effort could quickly clarify priorities and define a clear path forward.

6 Conclusion

The issues associated with integrating DERs into the grid are more complex and interdependent than it might initially seem. The jurisdictional issues and volume of policy-making activities in California's regulatory environment make it especially difficult to have a clear perspective of all the issues. An awareness and understanding of these issues that create challenges and barriers for DERs is necessary in order to develop a path for these resources to be a critical part of California's green grid future.

While many of the findings are not surprising, enumerating and suggesting potential mitigating actions illuminates a number of areas for focus to open opportunities for DER.

Although the number one barrier to entry for direct participation of demand response in the ISO, after completion of Electric Rule 24, is the lack of revenues available to resource owners from the wholesale market, there were six other key areas identified as having the most impact in advancing DER participation in the ISO markets. The first four of these items are ISO specific while others will require a greater level of coordination with other agencies. The first item in particular is ISO specific and expected to have the greatest impact. The impact anticipated for the following five were indistinguishable from each other during the analysis. These areas, described in detail in the report, are:

1. ISO metering and telemetry: completion of phases 1 and 2 of expanding the metering and telemetry stakeholder process to address the constraints and associated costs that are limiting innovative resource types and business models.
2. Sub-LAP and LSE aggregation boundaries: consider allowing resources to span sub-LAPs and possibly span LSEs.
3. AS certification processes: evaluate alternative ancillary services (AS) certification processes better suited for demand response and DERs.
4. Dynamic capacity resources: introduce bidding rules to address resources whose operating maximums vary dynamically.
5. Shared-purpose DERs such as microgrids: define options for supporting shared-purpose DERs so that many microgrid and electric vehicle projects could avoid full interconnection.
6. WDAT process: Provide guidance to stakeholders to clarify the interconnection process for wholesale participation (WDAT). The complexity of the interconnection process for resources that both supply and consume energy has kept these resources from engaging in the wholesale market.

This report was not intended to provide a detailed action plan to address all of the barriers or challenges but to provide a summary of these issues and a framework for discussion and prioritization. Resolution of these issues – both those highlighted here and others covered in previous sections – are long-term and complex in nature, involving more than one agency; however, significant progress in grid integration of DERs can be made by the ISO both independently and in collaboration with other agencies and stakeholders. We firmly believe that an understanding of these issues is critical to the energy future of California, co-funding the development of this report to support that effort. We are hopeful that this report will be a catalyst to help unite the various discussions around these issues and provide direction for valuable conversation among stakeholders.

We hope to see critical stakeholders engaged in supporting the prioritization effort and the subsequent development of an action plan in early 2014.

Appendix A Action Scores

The following table details the impact scores for the actions listed in Section 5. Each action is scored from 1 to 3 from low to high impact. The ultimate score is an average of the individual scores.

		Different Types?	System Impact	Addresses duck?	Multiple Issues?	Emerging Tech?	*Impact Score (Average)*
5.2.1	Improve Revenue Equality and Opportunity	3	3	3	1	3	**2.6**
5.2.2.1	Enhance PDR for Frequency Regulation	3	1	1	3	3	**2.2**
5.2.2.2	Add Capacity-only Frequency Regulation	3	1	1	3	3	**2.2**
5.2.2.3	Allow Resources to Span Sub-LAPs	3	2	2	2	2	**2.2**
5.2.2.4	Allow PDRs to Span LSEs	2	2	2	2	1	**1.8**
5.2.2.5	PDR Performance Measurement Options	2	2	2	1	2	**1.8**
5.2.2.6	PDR Registration Improvements	2	1	2	1	1	**1.4**
5.2.2.7	Evaluate Mass Market PDR Improvements	1	2	2	1	2	**1.6**
5.2.2.8	Improve DRS Integration Capabilities	2	2	2	1	2	**1.8**
5.2.3.1	Evaluate Energy Storage Modeling Improvements	2	3	1	1	3	**2.0**
5.2.3.2	Evaluate Certification Alternatives	3	2	2	1	3	**2.2**
5.2.3.3	Introduce Dynamic Capacity Resource Aware Bidding Rules	3	2	2	1	3	**2.2**
5.2.4.1	Enhance Documentation of PDR Integration Process	2	1	1	1	3	**1.6**
5.2.4.2	Combine PLA and PGA for NGR Implementation	2	2	1	1	3	**1.8**
5.2.4.3	Evaluate Streamlining NRI for Non-exporting NGRs	2	2	1	2	3	**2.0**
5.2.5	Simplify and Standardize WDAT and Process for DER	2	2	1	3	3	**2.2**
5.2.6.1	Complete Phases 1 and 2 of the Expanding Metering and Telemetry Options Proposals	3	2	2	3	3	**2.6**
5.2.6.2	UDC subtractive and/or logical metering	3	2	2	2	2	**2.2**
5.2.6.3	ISO / UDC Meter Sharing	2	1	1	1	2	**1.4**
5.2.6.4	Standardize process for and access to RQMD	2	1	2	1	2	**1.6**
5.2.6.5	Evaluate Telemetry Requirements for PDRs	1	2	2	1	2	**1.6**
5.2.7	Establish Rules and Pro-forma Agreements for DRP / LSE Cooperation	2	2	2	2	2	**2.0**
5.2.8	Sub-LAP Mapping System for Stakeholders	3	1	2	1	2	**1.8**
5.2.9	Introduce Lab Environment for Regulation	3	1	1	1	3	**1.8**

The following table details the scores for ease of effort for the actions listed in Section 5. Each action is scored from 1 to 3 with a 1 indicating greater and a 3 easier implementation effort. The ultimate score is an average of the individual scores.

		Regulatory Change?	**Multi-party?**	**Process or proceeding?**	**System Changes?**	**Path clear?**	***Effort Score (Average)***
5.2.1	Improve Revenue Equality and Opportunity	1	1	1	2	2	**1.4**
5.2.2.1	Enhance PDR for Frequency Regulation	2	3	2	3	2	**2.4**
5.2.2.2	Add Capacity-only Frequency Regulation	2	3	3	3	2	**2.6**
5.2.2.3	Allow Resources to Span Sub-LAPs	3	3	3	3	2	**2.8**
5.2.2.4	Allow PDRs to Span LSEs	1	1	1	1	2	**1.2**
5.2.2.5	PDR Performance Measurement Options	1	1	1	2	2.	**1.2**
5.2.2.6	PDR Registration Improvements	3	3	3	2	2	**2.6**
5.2.2.7	Evaluate Mass Market PDR Improvements	2	1	1	1	1	**1.2**
5.2.2.8	Improve DRS Integration Capabilities	3	3	3	2	3	**2.6**
5.2.3.1	Evaluate Energy Storage Modeling Improvements	3	3	3	2	1	**2.4**
5.2.3.2	Evaluate Certification Alternatives	3	3	3	3	1	**2.6**
5.2.3.3	Introduce Dynamic Capacity Resource Aware Bidding Rules	2	3	2	2	2	**2.2**
5.2.4.1	Enhance Documentation of PDR Integration Process	3	3	3	3	3	**3.0**
5.2.4.2	Combine PLA and PGA for NGR Implementation	2	3	3	3	3	**2.8**
5.2.4.3	Evaluate Streamlining NRI for Non-exporting NGRs	2	1	2	3	1	**1.8**
5.2.5	Simplify and Standardize WDAT and Process for DER	1	1	2	3	1	**1.6**
5.2.6.1	Complete Phases 1 and 2 of the Expanding Metering and Telemetry Options Proposals	2	3	3	2	2	**2.4**
5.2.6.2	UDC subtractive and/or logical metering	1	1	2	2	1	**1.4**
5.2.6.3	ISO / UDC Meter Sharing	1	1	1	2	1	**1.2**
5.2.6.4	Standardize process for and access to RQMD	2	2	2	2	3	**2.2**
5.2.6.5	Evaluate Telemetry Requirements for PDRs	2	3	3	3	1	**2.4**
5.2.7	Establish Rules and Pro-forma Agreements for DRP / LSE Cooperation	2	2	2	3	1	**2.0**
5.2.8	Sub-LAP Mapping System for Stakeholders	3	3	3	1	2	**2.4**
5.2.9	Introduce Lab Environment for Regulation	3	3	3	3	2	**2.8**

Appendix B Glossary and Definitions

Term	Definition
AGC	Automatic generation control: The system that directly controls the output of resources through a signal from the ISO Energy Management System
CPUC	California Public Utilities Commission: Has regulatory jurisdiction over the investor-owned utilities in California.
DDR	Dispatchable-demand resource: Demand as a resource that is bid directly into the ISO market and that can offer all ancillary services including regulation. This was a type of NGR contemplated in the past.
DLA	Default load adjustment: An adjustment made to the metered load of an LSE to account for market participation of demand response.
DR	Demand response
EMS	Energy management system: The ISO internal system that monitors real-time grid conditions and determines instantaneous system regulation requirement
FERC	Federal Energy Regulatory Commission: Federal body with regulatory jurisdiction over wholesale energy markets.
FNM	Full network model: The ISO computer based model that includes all system loads, resources and transmission facilities
GRDT	Generator resource data template : A spreadsheet that contains comprehensive operational resource characteristics
IOU	Investor owned utility: The group of utilities overseen by the CPUC: Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric.
LSE	Load serving entity: An organization that provides energy to customers, either an electric utility or a third party energy service provider (ESP).
LESR	Limited energy storage resource: A resource that can provide both generation and load continuously from negative to positive output and allows for injection onto the grid; all NGRs today are LESRs.
NBT	Net benefits test: The process to determine the price at which demand response is a cost effective resource.
NGR	Non-generator resource: Resources that operate as either generation or load and can be dispatched to any operating level within their entire capacity range but are also constrained by a MWh limit to do the following on a continuous basis: (1) generate energy, (2) curtail the consumption of energy in the case of demand response, or (3) consume energy
PDR	Proxy demand resource: A resource type at the ISO designed for participation of economic demand response in energy and non-spinning reserves.
PEV	Plug-in electric vehicle.
RDRR	Reliability demand response resource: A resource type at the ISO designed for participation of emergency demand response in the markets.
REM	Regulation energy management: a market feature for NGRs to offer their full capacity for frequency regulation. Resources using REM may only provide frequency regulation.
SC	Scheduling coordinator: The type of entity through which ISO conducts all market related and financial transactions

SOC	State of charge: Indicates the stored energy within a storage resource.
UDC	Utility distribution company: An organization that supplies electricity distribution infrastructure and services
VGI	Vehicle-grid integration: General term for integrating an electric vehicle with the electricity grid and includes both unidirectional and bidirectional services.

Appendix C References

i. The *Changing Net Load Pattern* chart was originally included in ISO Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources and is included with permission of the ISO. That report is available at http://www.caiso.com/Documents/DR-EERoadmap.pdf.

ii. The NRI Process chart is from version 1 of the ISO New Resource Implementation Guide.

iii. For more information on the PG&E Yerba Buena Battery Energy Storage Pilot Project http://www.energystorageexchange.org/projects/362.

iv. The ISO Metering Business Practice Manual contains specifics on the PDR baseline and can be found on the following page http://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx