Energy Storage and Distributed Energy Resources (ESDER) Stakeholder Initiative

Draft Final Proposal

November 2, 2015

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1 Introduction

Enhancing the ability of transmission grid-connected storage and the many examples of distribution-connected resources (i.e., distributed energy resources or "DER") to participate in the ISO market is the central focus of the ISO's energy storage and distributed energy resources (ESDER) stakeholder initiative.

In this paper, the ISO presents its draft final proposals on the topics in scope for the 2015 phase of the ESDER initiative. The 2015 scope comprises three topics: a limited set of enhancements to the ISO non-generator resources model ("NGR"), enhancements to the ISO demand response participation models (proxy demand resource or "PDR" and reliability demand response resource or "RDRR"), and addressing questions associated with non-resource adequacy multiple-use applications. A more extensive set of issues will be addressed in the second phase of the ESDER initiative in 2016.

2 Summary of revisions to revised straw proposal and response to comments

In this draft final proposal, the ISO has made several clarifications and revisions relative to the revised straw proposal (i.e., the previous paper produced in this initiative) based on stakeholder comments received and on further consideration by the ISO. These comments and revisions are summarized below in each of the three primary topic areas addressed in the 2015 scope of ESDER: non-generator resource (NGR) enhancements; proxy demand resource (PDR) and reliability demand response resource (RDRR) enhancements; and multiple-use applications.

2.1 NGR enhancements

2.1.1 NGR documentation

Stakeholders support additional NGR documentation. Some stakeholders further request that the ISO provide a document specific to NGR operations. The ISO agrees that additional documentation on NGR would be helpful and proposes to add further documentation on NGR in its BPMs rather than create a separate NGR document. This is discussed in section 5.2.1.

2.1.2 Clarification about how the ISO uses "state of charge" in the market optimization

Stakeholder comments were received that support the need for additional BPM documentation about how the state of charge affects market optimization and dispatch. The ISO agrees this would be helpful. Certain stakeholders have further requested the actual SOC mathematical formulation used in the NGR model, however, the ISO cannot provide this level of detail as this is proprietary information. The ISO is prepared to provide documented examples of how SOC affects market optimization and dispatch and discuss specific operational outcomes from participating resources as the resource owner develops expertise with the NGR model. SOC clarification will be included in the updated NGR documentation being developed within the ISO BPMs and as further described in section 5.2.2.

2.1.3 Allow initial state of charge as a bid parameter in the day-ahead market

Comments from stakeholders support this proposed enhancement to the NGR model to better allow resource owners to communicate initial SOC values to the ISO when commencing or restarting market participation. Some stakeholders requested clarity if there would be any restrictions on the value of the initial SOC, or on any requirements to be at (or close to) that SOC. The ISO proposes to allow for the initial SOC as a day-ahead market bid parameter and addresses these comments in section 5.2.3.

2.1.4 Allow an option to not provide energy limits or have the ISO co-optimize a NGR based on state of charge

Stakeholders support this enhancement to the NGR model. The submitted comments described several factors in which having the ISO optimize and dispatch a resource based on SOC was less desirable than having the resource owner self-manage the resource's participation based on their understanding of the resources capabilities. One stakeholder requested information on why the ISO still needed telemetered SOC when this value would not be used in optimization and dispatch. The ISO clarifies that if a SOC value exists or can accurately be derived, this value should still be provided to the ISO for performance monitoring needs even if the ISO is not using this value for market optimization and dispatch. The ISO proposes to provide an option that allows resources to participate under NGR without utilizing SOC and energy limit constraints as described in section 5.2.4.

2.2 PDR/RDRR enhancements

2.2.1 Alternative performance evaluation methodology

The ISO included in its revised straw proposal several performance evaluation options it was considering including use of metering generator output (MGO) concepts. While stakeholders support including a MGO performance evaluation methodology, stakeholders raised several concerns. Some stakeholders expressed concern that an MGO proposal may require complementary, or conflict with, local regulatory authority (LRA) rules and procedures. In response, the ISO points out that existing rules already require that meter standards comply with LRA requirements (see tariff section 10.3.7) and the ISO is not proposing to change this requirement. The ISO and some stakeholders expressed concern about the "frequent" generation issue and how an MGO proposal could discern wholesale, supply-side demand response from other retail, load modifying uses such as retail rate arbitrage absent employing a baseline. Through a series of working group discussions the ISO proposed ideas to address this concern while soliciting additional input and ideas on possible revisions to the draft ISO proposal to address whether and how performance from devices behind the meter that provide frequent load modifying response should be measured for wholesale demand response compensation purposes.

The ISO presents its draft final proposal in section 6.3.1 of this paper based on these working group discussions and stakeholder input. The ISO believes its proposal strikes a reasonable balance between concerns about MGO and the need to evolve the PDR/RDRR framework to enable frequent participation from customers with advanced technologies like energy storage. Some stakeholders have suggested that a "sunset" be placed on this proposed approach or that it be treated as a "pilot." The ISO supports neither of these ideas but instead will explore what modifications to this approach may be appropriate in the 2016 phase of the ESDER initiative, especially once operational experience has been gained with resources using MGO concepts.

Some stakeholders have also suggested that a coordinated effort with the distribution utilities and their local regulatory authorities (e.g., SDG&E, SCE, PG&E and the CPUC) is essential to enable the successful integration and operation of these resources. The ISO agrees and looks forward to continuing to work with stakeholders to identify and resolve issues, lower barriers, and refine its market design.

2.2.2 Baseline Type-II

The ISO includes in this draft final proposal a proposal to support the use of statistical sampling for real-time and ancillary services participation when interval metering installed at all underlying resource locations is not recorded in 5- or 15-minute intervals (see section 6.2.2). There is general stakeholder support for the ISO's proposal. However, stakeholders asked for clarification on the definition of "interval metering" and how tariff section 10.1.7 applies. The ISO provides further clarification on this point in this paper. Additional working group comments were considered in developing this draft final proposal including the concern that the ISO is being too conservative in its proposed statistical sampling methodology. While the draft final proposal is not substantively different from the revised straw proposal, additional explanation and clarification about the ISO's approach is provided.

2.3 Multiple-use applications

In this initiative, the ISO addresses two broad types of multiple-use applications: (1) the DER aggregation (DERA) provides services to the distribution system and participates in the wholesale market; and (2) the DERA provides services to end-use customers and participates in the wholesale market. Both types are treated in the context where the DERA or a set-aside portion of its capacity is not providing resource adequacy capacity to a load-serving entity for the given month. For these applications, the ISO draft final proposal is consistent with the revised straw proposal; specifically:

1. The ISO will require settlement quality meter data (SQMD) from the SC for a DERA to be submitted on a daily basis in accordance with ISO settlement timelines, and will settle the DERA based on that SQMD, for all market intervals, not just those intervals in which the DERA was issued an ISO schedule or dispatch instruction. The ISO recognizes that many stakeholders favor a change in this requirement to allow a DERA to be settled through the ISO only for intervals in which the DER explicitly participates in the ISO market, and will consider this change in the 2016 scope of the ESDER initiative. PDR/RDRR resources will continue to provide SQMD and be settled through the ISO market in those intervals when the PDR/RDRR resource was dispatched by the ISO.
2. The ISO does not propose to establish priority rights to DER to address instances where service to the distribution system may conflict with an ISO dispatch instruction. The ISO will settle deviations by a DER from its dispatch instruction as uninstructed imbalance energy (UIE).
3. The ISO does not propose to implement provisions at this time to address potential "double payment" situations where a DER/DERA is compensated by the distribution utility for performance that aligns with the DER's response to an ISO dispatch instruction. The ISO believes such questions are better addressed after specific distribution system services by DER have been defined.
4. The ISO does not propose to implement limitations on the provision of distribution system services by sub-resources of a DERA.
5. The ISO believes that the PDR/RDRR enhancements topic in this initiative (specifically, the issues addressed in section 6.2.1 of this paper) effectively deals with scenarios where DER provide services to end-use customers and participate in the ISO markets. The ISO will consider whether the 2016 ESDER scope should include any additional issues related to such scenarios, and does not see a need to address any additional topics regarding multiple-use associated with the provision of distribution services at this time.

3 Background

Energy storage connected directly to the ISO grid and resources connected directly to the distribution grid (distributed energy resources or "DER") are growing and will represent an increasingly important part of the future resource mix.[1] Integrating these resources will help lower carbon emissions and can offer operational benefits.

California is taking several steps to facilitate market participation of storage and aggregated distributed energy resources. In 2013, the CPUC established an energy storage procurement target of 1,325 MW by 2020. Energy storage developers responded by submitting many requests to interconnect to the ISO grid in the spring of 2014. Interconnection requests received in 2014 currently include approximately 780 MW of energy storage (13 projects), while the 2015 interconnection requests as of June 2015 included approximately 7,300 MW of energy storage (66 projects), a jump of nearly 1000%.[2]

In 2013, the ISO conducted an effort to clarify interconnection rules for storage. This effort concluded in 2014 and found that existing ISO interconnection rules accommodate the interconnection of storage to the ISO controlled grid.[3] However, in reaching this conclusion the ISO and stakeholders identified several non-interconnection related issues that should also be addressed. To address these issues, the ISO collaborated with the CPUC and CEC to publish the California Energy Storage Roadmap in late 2014.[4]

The 2014 roadmap identified a broad array of challenges and barriers confronting energy storage and aggregated distributed energy resources. The roadmap also

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[1] Distributed energy resources are those resources on the distribution system such as rooftop solar, energy storage, plug-in electric vehicles, and demand response.

[2] Queue clusters 7 and 8 include interconnection requests received in April 2014 and April 2015, respectively. The latest ISO generator interconnection queue is available on the ISO website at http://www.caiso.com/participate/Pages/Generation/Default.aspx.

[3] http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorageInterconnection.aspx

[4] http://www.caiso.com/informed/Pages/CleanGrid/EnergyStorageRoadmap.aspx

identified needed actions to address these challenges, including several high priority action items assigned to the ISO. These are listed below:

- Rate treatment: Clarify wholesale rate treatment and ensure that the ISO tariff and applicable BPMs and other documentation provide sufficient information.
- Market participation:
  - Clarify existing ISO requirements, rules and market products for energy storage to participate in the ISO market.
  - Identify gaps and potential changes or additions to existing ISO requirements, rules, market products and models.
  - Where appropriate, expand options to current ISO requirements and rules for aggregations of distributed storage resources.

The ISO action plan for carrying out these items comprises two parts. The first part is to help inform stakeholders on existing ISO requirements, rules, market products and models for energy storage and aggregated DER. The ISO accomplished this first part by developing a special purpose education forum and hosting it on two dates – April 16 and 23, 2015. The forums were a success: Over 200 stakeholders attended and the feedback received was positive.

The second part of the ISO action plan is to conduct a stakeholder initiative to identify and consider potential enhancements to existing requirements, rules, market products and models for energy storage and DER market participation. The ESDER is that initiative. As an initial step, the ISO worked with stakeholders to develop a scope of issues in the ESDER initiative and a schedule for resolving them. The scope and schedule includes one set of issues in 2015 and a second set of issues in 2016 and beyond. On July 30, the ISO posted an issue paper and straw proposal on the issues in the 2015 scope. Following receipt of stakeholder comments the ISO developed a revised straw proposal and posted that on September 17. Subsequent to another round of stakeholder feedback, including that resulting from two working group meetings in October, the ISO developed its draft final proposal and presents that in this paper.

4 Stakeholder process

The ISO published an initial proposed scope and schedule for the ESDER initiative on May 13, 2015. This effort identified candidate issues and divided them into two groups – a proposed scope of issues for potential policy resolution in 2015 and a proposed scope of issues for potential policy resolution in 2016 and beyond. A stakeholder web conference was held on May 21 and written stakeholder comments were received on or about May 29.

Based on a consideration of the stakeholder comments received, the ISO developed the revised scope and schedule and posted that on July 25.[5] The ISO considered the July 25 scope and schedule final and used it as the work plan for this initiative. The ISO invited interested stakeholders to submit written comments on the scope and schedule by July 2. The ISO addressed these comments in its issue paper and straw proposal posted on July 30. The ISO discussed the July 30 paper with stakeholders during a web conference held on August 6 and invited stakeholders to submit written comments on the paper by August 18. Based on a review of the stakeholder comments received and further consideration by the ISO, the ISO developed its revised straw proposal and posted that on September 17. This was followed by a stakeholder web conference on September 28 and written comments were received on or around October 9. The ISO then held two working group meetings in October focused on the PDR/RDRR enhancements and received written stakeholder comments following these meetings.

After giving consideration to all of the stakeholder input received up to that point, the ISO developed its draft final proposal and presents that in this paper. The next step will be to discuss this paper with stakeholders during a web conference scheduled for November 9 from 1:00 p.m. to 4:00 p.m. (Pacific). Following that, the ISO is inviting stakeholders to submit written comments to InitiativeComments@caiso.com by 5:00 p.m. (Pacific) on November 20. The ISO will present its proposals to the Board at its December meeting and request authorization to revise its tariff for those proposals requiring tariff change.

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[5] All documents for the ESDER initiative are available on the ISO's website at: http://www.caiso.com/Documents/RevisedScopeSchedule-EnergyStorageDistributedEnergyResources.pdf

The following table outlines the schedule for the policy development portion of this stakeholder initiative for those issues in the 2015 scope. This schedule does not include implementation steps including development and filing of tariff amendments, changing business process manuals, and making and implementing changes to market system software and models. These would take place in 2016.

Stakeholder Process Schedule (for the scope of issues identified for potential policy resolution in 2015)		
Step	**Date**	**Activity**
Education Forum	April 16 & 23	Hold education forums
Initial proposed scope and schedule	May 13	Post initial proposed scope and schedule (posted in presentation format rather than a paper)
	May 21	Stakeholder web conference
	May 28	Stakeholder comments due
Revised scope and schedule	June 25	Post revised scope and schedule
	July 2	Stakeholder comments due
Issue paper and straw proposal	July 30	Post issue paper and straw proposal
	August 6	Stakeholder web conference
	August 18	Stakeholder comments due
ESDER Working Group	August 27	ESDER working group web conference
	September 3	Stakeholder comments due
Revised straw proposal	September 17	Post revised straw proposal
	September 28	Stakeholder web conference
	October 9	Stakeholder comments due
ESDER Working Group	October 12	ESDER working group meeting
	October 19	Stakeholder comments due
ESDER Working Group	October 27	ESDER working group web conference
	October 29	Stakeholder comments due
Draft final proposal	November 2	Post draft final proposal

Stakeholder Process Schedule (for the scope of issues identified for potential policy resolution in 2015)		
Step	**Date**	**Activity**
	November 9	Stakeholder web conference
	November 20	Stakeholder comments due
Board approval	December 17-18, 2015	ISO Board meeting

Regarding the proposed scope of issues for potential policy resolution in 2016 and beyond, the ISO intends to delay work until early 2016. Taking this approach maximizes the potential for bringing proposed resolutions to the 2015 scope of issues to the Board by December 2015.

5 NGR enhancements

5.1 Background on the NGR model

As early as 2007, the ISO launched stakeholder initiatives that began to lay the foundation to allow non-traditional generator resources to participate in the ISO wholesale market. These initiatives were largely in response to FERC Order Nos. 719 and 890. FERC Order No. 719 directed the ISO to allow demand response resources to participate in ancillary service markets where the resources could technically provide the ancillary service within response times and other reasonable requirements adopted by the ISO.

FERC Order No. 890 required that non-generation resources such as demand response must be evaluated comparably to services provided by generation resources in the areas of meeting mandatory reliability standards, providing ancillary services, and planning the expansion of the transmission grid.

Because of these initiatives, in 2010, the ISO changed its tariff for ancillary service wholesale participation:

- Removed resource type restrictions and reduced minimum rated capacity to 500 kW from 1 MW
- Reduced the minimum continuous energy requirement from 2 hours to:
  - Day-Ahead Regulation Up/Down: 60 minutes
  - Real-Time Regulation Up/Down: 30 minutes
  - Spin and Non-Spin: 30 minutes
- Clarified the minimum continuous energy measurement such that continuous energy is measured from the period that the resource reaches the awarded energy output, not at the end of a 10-minute ramp.

In broader context, these initiatives were a catalyst for developing new market opportunities and modeling techniques that recognized that a growing number of participating resources no longer fit the traditional generator or load models. Non-generator resources such as demand response and storage have unique energy use and production characteristics that have spawned the development of new wholesale participation models that recognize the unique attributes of these resources.

In 2012, the ISO introduced the non-generator resource (NGR) model to better accommodate energy constrained resources that can both consume and produce energy. The NGR model was designed for energy constrained resources where operation could be modeled on the positive generation side, the negative generation side, or from positive to negative generation. The NGR model allowed smaller, energy-constrained resources to be treated comparably to traditional generation resources in qualifying for day-ahead capacity and continuous energy output when providing regulation services.

The NGR model recognizes that a resource can operate seamlessly between positive and negative generation. For example, battery storage is a resource which can discharge energy in one interval as positive generation and consume energy in the next interval as negative generation. Current battery chemistries and storage control systems have demonstrated these resources can move nearly instantaneously between positive and negative generation, have fast ramping rates, and can be controlled to high precision and performance accuracy. While storage technology is an ideal candidate for the NGR model, the model may also benefit other energy constrained resources such as dispatchable demand response or microgrid configurations that have limited ability to generate or consume energy continuously and can be directly metered. The NGR model is also envisioned by the ISO as the model best suited for aggregations of distributed energy resources.

5.2 Draft Final Proposal

5.2.1 NGR documentation

Feedback from the April education forums suggests that the forum included material and information not previously available about the NGR model and its capabilities. Although the ISO introduced the NGR model almost 3 years ago, the adoption rate has been slow because few energy storage projects have yet reached commercial operation.[6] However, the adoption rate is likely to increase with the advent of energy storage procurement targets for utilities, storage original equipment manufacturers (OEMs) reducing costs, and developers bringing projects to market. The timing is right for the ISO to review and enhance NGR documentation in anticipation of more storage devices participating in the ISO market as NGRs.

The ISO proposes to follow the established method of utilizing Business Practice Manuals (BPMs) to provide detailed rules, procedures and examples for the administration, operation, planning and accounting requirements of NGRs participating in the ISO market, consistent with the ISO tariff. The ISO does not create stand-alone, model specific documentation, but instead relies on BPMs to provide information on participation in the ISO markets.

BPM updates will include content that distinguishes differences in requirements between resources participating as NGR from NGR participating under the Regulation Energy Management (REM) option and provide additional detail on NGR participation as load or generation resources.

[6] Although there are many projects under development that could ultimately use the NGR model, they are not yet in commercial operation and thus are not available to participate in the ISO market and utilize the NGR model.

Multiple BPMs – including but not limited to Market Operations, Market Instruments, Direct Telemetry, Metering, Outage Management, Reliability Requirements, and Settlements and Billing – will be reviewed and updated where appropriate to reflect the most up-to-date information related to NGR requirements and operation.

5.2.2 Clarification about how the ISO uses "state of charge" in the market optimization

As designed and implemented, the NGR model applies to continuous energy constrained resources. The amount of a resource's available energy is a function of the resource's state of charge (SOC). The SOC is utilized for market resource co-optimization, real-time dispatch feasibility, and automatic generation control (AGC) signaling. For the ISO to observe this energy constraint, the resource's SOC must be provided to the ISO through telemetry. Telemetry plays an essential role in market optimization of awards, AGC signaling, and market dispatch.

Stakeholders have expressed the need to have more detail on how SOC influences model optimization and how it affects the mathematical formulation of economic dispatch. Several stakeholders requested numerical examples that describe how SOC affects the interplay between capacity and energy in sequential hours, and, information on how SOC is used in real-time AGC calculations for NGRs participating under the regulation energy management (REM) option under both normal and stressed grid conditions. Stakeholders also requested documentation that helps them understand the interplay and timing of when a particular four second telemetered SOC value is used in the real-time market processes which operate at different time intervals from AGC telemetry.

The ISO proposes to address the stakeholder need for clarity in SOC utilization by updating ISO BPMs with information that describes how SOC influences model optimization, impacts to mathematical formulation of economic dispatch, examples of how SOC impacts the interplay of capacity and energy over several market intervals, examples of how SOC is used in AGC calculations for resources under NGR REM, and the market interval timing between telemetered SOC values and actual market system use of the telemetered SOC value.

5.2.3 Allow initial "state of charge" as a bid parameter in the day-ahead market

Stakeholders point out that because the ISO assumes that the initial SOC value is 50% in the day-ahead market, the resource owner must manage the resource in a way to ensure that the initial day-ahead SOC is at this value or risk being awarded bids that create infeasible dispatches in the trading day. This could be especially difficult if there is significant real-time activity.

Under current rules, when an NGR bids into the day-ahead market, the initial SOC value used for that trading day is the ending SOC value from the previous day's day-ahead awards. When there are no previous day's day-ahead awards, the market system assumes that the initial SOC value for the resource is 50% of the maximum energy (MWh) limit, which is a parameter defined when the ISO models the resource in its network model. While the current approach is to begin day-ahead participation at an actual resource SOC of 50%, participants have suggested that another approach would be for the ISO to allow the initial day-ahead SOC value to be supplied as a daily bid component with the day-ahead bid schedule.

With the option of providing an initial SOC parameter, stakeholders would like the ISO to clarify how the daily bid SOC value is reconciled with the real-time SOC value passed in real-time telemetry and clarify day-ahead and real-time settlement rules when day-ahead SOC parameter values differ from real-time operation. Stakeholders have also asked the ISO to clarify if there would be any restrictions on the value of the initial SOC, or on any requirements to be at (or close to) that SOC value. The ISO does not propose to monitor the accuracy of day-ahead initial SOC bid parameter. The ISO believes that the resource owner will ensure this value will be accurate to maximize the value of the resource while participating in the market and to avoid uninstructed imbalance energy (UIE) settlement and infeasible dispatch situations (i.e., the resource owner/operator takes on the UIE risk).

While some stakeholders have commented that providing an hourly SOC value would provide more benefit than an initial daily value, the ISO is not considering an option to provide an hourly starting bid parameter for day-ahead participation. The ISO suggests that an option for NGRs that does not utilize SOC within energy limit constraints may be a better solution (see section 5.2.4 below).

Some stakeholders have asked for the ISO to provide an option to supply a minimum SOC parameter that the resource must have at the end of its awarded day-ahead schedule. While the ISO will observe physical constraints modeled for the resource, a desired ending SOC parameter is not a physical constraint, but an operational strategy determined by the resource owner. In these cases, the resource owner would alter their bidding strategy to affect the desired ending SOC. The ISO does not propose providing a minimum SOC parameter that the resource must have at the end of its awarded day-ahead schedule within this stakeholder process.

The ISO proposes to allow the ability to submit a daily SOC bidding parameter to initialize the ISO day-ahead market system. This option will include updates to the ISO's scheduling infrastructure business rules (SIBR)[7] system that would allow scheduling coordinators to submit a daily bid parameter for NGR SOC in both the SIBR user interface and the SIBR application programming interface (API). Rules must be established in the SIBR application such that the SOC parameter is used only on the first interval of participation for the trading day.

5.2.4 Allow an option to not provide energy limits or have the ISO co-optimize an NGR based on the "state of charge"

Stakeholders have suggested that NGR resources should not be required to provide energy limits or have the ISO co-optimize the resource based on SOC values. This request may be due in part to the lack of wholesale market participation experience with the NGR model and uncertainty of how SOC is used within the ISO co-optimization calculations and market dispatches. While the intent behind requiring the SOC value is

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[7] SIBR is an ISO application that provides scheduling coordinators access to the ISO market systems. SIBR functionality includes:

- Accepts bids and trades for energy and energy-related commodities from scheduling coordinators that are certified to interact with the ISO;
- Ensures that those bids and trades are valid and modified bids for correctness when necessary;
- Enters those bids and trades into a database for processing by other components of ISO's management systems; and
- Provides required feedback to scheduling coordinators concerning bids and trades that have been submitted.

to allow the ISO to maximize the value of this resource in the wholesale markets and to ensure that the resource is not given an infeasible dispatch or AGC signal, the ISO also recognizes there may be circumstances or conditions where the benefits of SOC co-optimization by the ISO may not materialize based on multiple use scenarios or where the SOC comprises an aggregation of resources where the SOC becomes variable.

The ISO proposes to allow an option for NGRs to be modeled similar to resources which manage participation within their energy constraints. This means that the scheduling coordinator would manage the SOC constraint and actively manage resource bids in the ISO real-time market in line with the resources ability to avoid non-performance conditions. Without SOC or energy limits, the ISO co-optimization process would not use these values when determining awards. If SOC values and energy limits are not provided, the ISO would assume that the NGR did not have these constraints.

Under this option:

- NGRs that do not have SOC energy limits or choose to self-manage the SOC within resource energy limit constraints may choose to not use energy limit constraints and SOC in co-optimization or dispatch.
- NGRs that have a SOC and choose to self-manage their SOC, must provide telemetry SOC values for ISO resource performance monitoring.

Resources modeled under NGR REM would not be allowed this option given the need for the ISO to maintain the resource's energy state and SOC for continuous energy output. Without real-time telemetered SOC and energy limit constraints, the ISO could not manage continuous energy requirements.

6 PDR/RDRR enhancements

6.1 Background on performance evaluation methodologies

A commonly used performance evaluation methodology for demand response is a "baseline." A baseline calculates a "counter-factual" value, a theoretical measure of how much energy a customer would have consumed had there not been a demand response event. The baseline calculation compares the customer's counter-factual energy use to actual energy use during the demand response event. The difference between the two is the "nega-watts" delivered, i.e., the actual energy reduction a demand response resource delivered during the event. Since only the physical load can be metered and not the demand response quantity, the result of the baseline calculation compared against the actual load during the ISO dispatch time horizon serves as the demand response energy measurement used by the ISO to financially settle the energy delivered (*i.e.,* energy not consumed) from a demand response resource.

The North American Energy Standards Board (NAESB), responsible for developing and promoting industry standards, published a standard for demand resource performance evaluation methodologies.[8] It provided standard terminology and identified five broad types of performance evaluation methodologies:

1) Baseline Type-I: A baseline performance evaluation methodology based on historical interval meter data for a demand resource that may include other parameters such as weather and calendar data;
2) Baseline Type-II: A baseline performance evaluation methodology that uses statistical sampling to estimate the electricity usage of an aggregated demand resource where interval metering is not available on the entire population;
3) Maximum Base Load (MBL): A baseline performance evaluation methodology based solely on the ability of a demand resource to maintain its electricity usage at or below a specified level during a response event;
4) Meter Before/Meter After (MB/MA): A baseline performance evaluation methodology in which electricity demand over a prescribed period of time prior to resource deployment is compared to similar readings during the sustained response period; and

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[8] Measurement and Verification of Wholesale Electricity Demand Response – NAESB WEQ-015; July 31, 2012.

5) Metering Generator Output (MGO): A performance evaluation methodology in which the demand reduction value is based on the output of generator located behind the revenue meter for the demand resource.

The ISO tariff provides for use of two of these five NAESB approved performance evaluation methodologies: Baseline Type-I and Baseline Type-II. NAESB standards, including WEQ-015, Measurement and Verification of Wholesale Electricity Demand Response, are included in the ISO tariff by reference in section 7.3.3; however, the NAESB naming terminology is not replicated in the ISO tariff. The ISO tariff addresses the equivalent of the NAESB Baseline Type-I in tariff section 4.13.4 ("Customer Baseline Methodologies for PDR/RDRRs and RDRRs") and NAESB Baseline Type-II in tariff section 10.1.7 ("Provision of Statistically Derived Meter Data"). For this discussion, this paper refers to these as "ISO Type I" and "ISO Type 2" respectively to help clarify the relationship.

ISO Type 1 is the most commonly used baseline method for performance measurement of demand response resources among ISOs and regional transmission organizations. This method uses historical meter data from the facility to calculate the baseline for the demand response resource with defined selection rules including baseline window and exclusion days. It employs an adjustment method for aligning the preliminary baseline with observed load prior to the event to minimize baseline errors. The adjustment uses actual load data in the hours preceding the event to adjust the baseline to better reflect the variables that may not be represented in the historical data (e.g. the impact of weather on load). ISO Type I uses the 10-in-10 non-event day methodology as described in section 4.13.4.1 of the tariff utilizing both baseline selection and exclusion rules. Under this methodology, the ISO examines up to 45 days prior to the trade day to find ten "like" days. The ISO then calculates a simple hourly average of the collected meter data to create a load profile, which is then used as the baseline to assess the event-day load response quantity. A day-of adjustment capped at ± 20 % is applied based on an adjustment window preceding the resource dispatch.

ISO Type 2 provides for statistical sampling of a demand response resource's energy usage data to derive the settlement quality meter (SQMD) data submitted to the ISO representing the total energy usage, in aggregate, for the demand response resource. It is best used for large, direct load control aggregations (e.g., residential A/C cycling) that are homogeneous, exhibit similar behavior, and where interval meter data is not available across the entire population. ISO Type 2 is described in section 10.1.7 of the tariff and allows for the submittal of SQMD for the aggregated resource to be estimated based on a representative sample of interval meter data scaled to represent the entire population of underlying service accounts.

Stakeholders have expressed concern there may be ambiguity as to the precise meaning of “where interval metering is not available” as stated in the tariff. It is accepted that while there may be interval metering installed for the entire population of a demand resource, meter data cannot be provided in either the interval level needed for some levels of ISO participation (i.e. 5- or 15-minute granularity) or may not be available within the timeframe that it is need to produce and submit settlement quality meter data for the entire population to meet the ISO submittal deadlines. To facilitate the use of ISO Type 2, stakeholders have requested the ISO develop a “representative sample” technique based on an ISO defined set of statistical sampling principles including, but not limited to, establishing precision and accuracy requirements. The ISO’s proposal below (see section 6.2.2) contains both clarification on applicability and provision of detail on a proposed ISO statistical sampling method that would provide an approved statistical sampling methodology for settling demand response resource participation in the ISO market under section 10.1.7 of the ISO tariff.

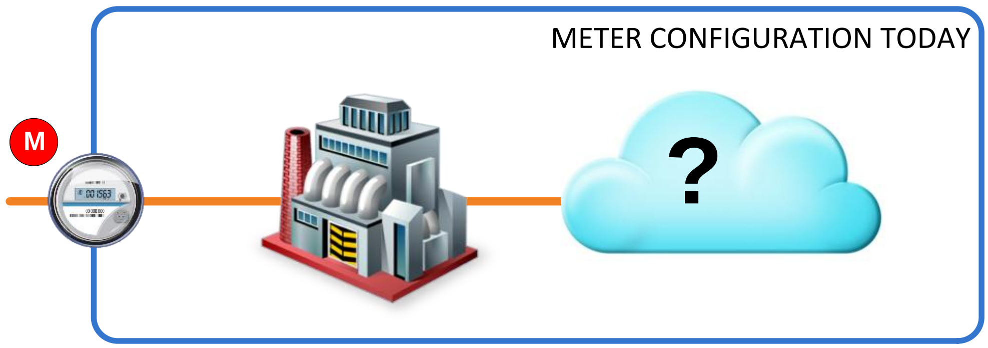
Stakeholders also requested clarification regarding use of a control group to establish a statistical sample for performance measurements for varying resource classes. However, since this topic is not specifically addressed by section 10.1.7 and since for ISO Type 2, the 2015 scope of ESDER is limited to clarifying existing tariff rules rather than creating new tariff rules, the ISO is not proposing to address the use of a control group at this time.

6.2 Draft Final Proposal

6.2.1 Alternative performance evaluation methodology

Today, a typical PDR/RDRR resource comprises a physical meter (labeled as M in figure 1 below) connected to a load. The load may be a pure load, or it may be offset by "behind-the-meter" generation or other device, such as battery storage. The presence of such a load offsetting device is depicted in the Figure 1 below as a cloud labeled with a question mark to illustrate that under such a metering configuration both its presence and composition are unknown to the ISO.

Figure 1



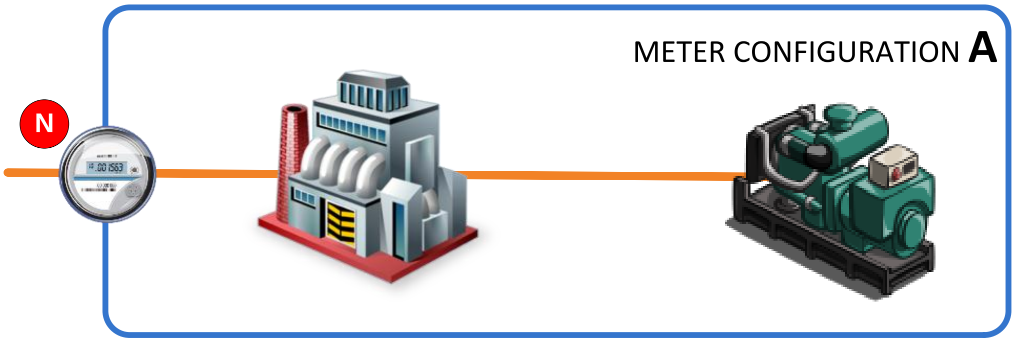
With such a metering configuration, there is no way to separate the load from the generation or vice versa. The ISO cannot distinguish the cause of demand response behind the meter. Some stakeholders have asked about an alternative performance evaluation methodology that directly meters the behind-the-meter device to measure the demand response provided by the device separate from the facility load.

NAESB's Metering Generator Output (MGO) model was established to allow for a back-up generator to offset load and serve as demand response. Per NAESB, MGO is "a performance evaluation methodology used when a generation asset is located behind the Demand Resource's revenue meter, in which the "Demand Reduction Value is based on the output of the generation asset."

To describe the options the ISO is proposing, the ISO has developed metering configurations A, B, and C. These are used throughout the remainder of this discussion to illustrate different demand response scenarios.

Consider meter configuration A illustrated in Figure 2 below. This is essentially identical to today's PDR/RDRR configuration other than the generation being formally recognized and the meter (M) has been relabeled as (N) to recognize it as a net meter representing the net effect of the load being offset by the behind-the-meter generation. But just as with today's PDR/RDRR configuration depicted in Figure 1, the performance cannot be separated into the two response methods (*i.e.,* actual load reduction versus load consumption offset by output from a behind-the-meter generator or device).

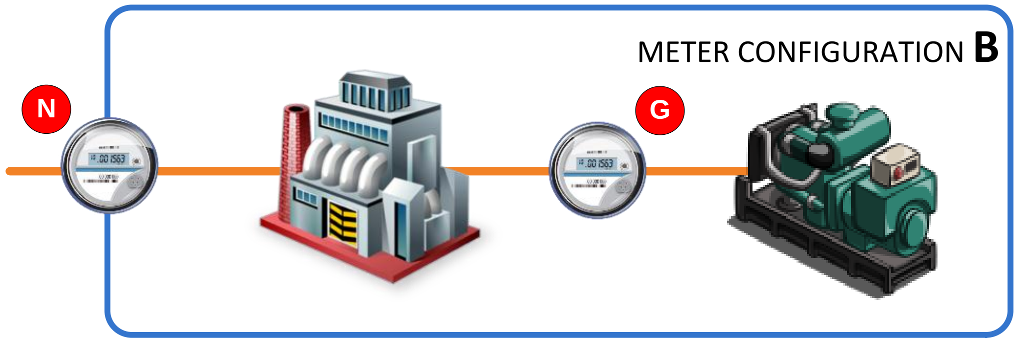
Figure 2



This configuration is supported by current ISO rules which establish a baseline using the physical meter (N) usage data. One issue with this configuration is that a PDR/RDRR resource that relies on a behind-the-meter generator, or device used frequently, such as an energy storage unit, may have an unpredictable load shape and, therefore, an inability to derive a reasonable, predictable baseline-load profile to derive performance during a demand response dispatch event. If one excludes days with frequent generation from the baseline calculation (assuming they can be identified), the number of available days for evaluation could become small and make it difficult to find ten comparable non-event days. It is reasonable to presume that a battery may charge every night and discharge every day based on many external variables and incentives not captured in existing performance evaluation methods. Some devices may be more difficult to model –electric vehicle charging (or discharging) whenever the homeowner plugs the vehicle into a home charging station.

Now consider meter configuration B as illustrated in Figure 3 below. Meter configuration B adds a generation meter to the diagram so the pure load may be derived as the difference (N-G)[9] between the net meter (N) and the generation or device meter (G).

Figure 3



Under this configuration, the overall demand response at the location could be separated into a pure load response and a generator or device response. Measurement of the location's reduction in consumption through traditional load response would employ a standard ISO type 1 baseline and performance evaluation method using N minus G for time interval t, or N(t) – G(t), as a derived "virtual" meter quantity, whereas the load consumption offset by the generation or device would use the MGO method using the physical meter G to directly measure its performance. As an example, if N(t) = 8 MWh and G(t) = -2 MWh, the virtual load meter quantity at time interval t would be L(t) = N(t) – G(t) = 10 MWh, where a metered quantity is assumed positive for load (consuming energy) and negative for generation (producing energy). The L(t) = 10 MWh would be the calculated quantity used to develop a baseline and performance evaluation for the traditional load response. While in its revised straw proposal the ISO considered the directly measured metered quantity G(t) to be the metered quantity used to establish the MGO demand response performance evaluation, the ISO now proposes to require the establishment of an adjustment to this quantity to mitigate issues of wholesale and retail service provision overlap.

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[9] In this discussion, with respect to formulas provided, we follow the sign convention that a load is expressed as a positive quantity, whereas the output of a generator or a discharging storage device is a negative quantity. This sign convention does not necessarily reflect a metering sign convention which distinguishes load versus generation by metering channel.

Further, the ISO is offering three possible PDR/RDRR participation options under meter configuration B, each with its own application of Baseline Type-I and the MGO performance evaluation methodologies. The proposals developed reflect refinements to address concerns of both the ISO and stakeholders on the need to separately distinguish the quantity of output in response to a PDR/RDRR wholesale dispatch from retail load modifying use. The ISO proposal options are described as follows:

Option B1 – Load Reduction Only. Under this option only the load would be registered in the PDR/RDRR and the demand response performance would be evaluated using a baseline (B) determined from N-G values for comparable non-dispatch hours. The actual demand reduction of the load in response to an ISO dispatch interval (t) would then be calculated as:

$$DR_{LOAD}(t) = B_{N\text{-}G}(t) – [N(t) – G(t)]$$

Option B2 – Generation Offset Only. Under this option only the generation device would be registered in the PDR/RDRR and the demand response performance would be evaluated based on the physical meter generator output G for dispatch interval (t), or G(t), adjusted by a quantity representing an estimation of typical retail load modifying behavior of that metered device. This calculated value, G_{LM}[10], would recognize and remove an estimation of the energy output representing typical retail load modifying behavior not in response to an ISO PDR/RDRR dispatch. The performance evaluation would be an adjusted MGO value calculated by taking the difference between G(t) and $G_{LM}(t)$ for the dispatch interval t, where the demand response performance attributed to a PDR/RDRR supply dispatch would be calculated as:

$$DR_{SUPPLY}(t) = – [G(t) – G_{LM}(t)]$$

PDR/RDRR cannot export energy during ISO dispatch intervals. The scheduling coordinator for the demand response provider (DRP) is required to test its settlement quality meter data before submission to the ISO against the net export check described

[10] $G_{Load\ Modifying}$ or G_{LM} is an ISO term used to represent an estimated value of the typical retail load modifying behavior of the behind the meter generating device.

in Table 1. Specifically, the scheduling coordinator acting as the scheduling coordinator metered entity must ensure that for each sub-resource that makes up a PDR/RDRR aggregation, the facility meter "N" minus the output from the behind-the-meter device metered by "G" must be greater than or equal to zero. The ISO retains the authority to audit both the N and G meter data values submitted by the scheduling coordinator acting as the scheduling coordinator metered entity to ensure compliance against the no export rule as described in Table 1.

$DR_{SUPPLY}(t)$is the demand reduction resulting from the output of the behind-the-meter generator or device.

The adjustment for typical retail load modifying behavior, G_{LM}, would be established through a look back of metered generator output values during similar ISO non-event days using rules established under ISO's existing baseline methodology including using a 10-in-10 non-event day selection method to obtain an average of the MGO in the last 10 eligible days for the applicable hours or intervals over a look back period of 45 calendar days. The baseline established in this instance is a "baseline" of the metered generation/device, not a baseline of the metered load.

Following are the rules the ISO would employ to calculate G_{LM} (note these rules adhere closely with the ISO's existing rules for ISO Type 1 baseline calculations):

- 10-in-10 non-event day selection method (an average of the MGO in the last 10 eligible non-event days for the applicable event-day hour(s) or interval(s)).
- A look back window will be 45 calendar days from which the 10 most recent eligible days will be selected.
- The selection of this load modifying "baseline" data will include several most recent days, excluding different day-types and previous events days.
- Two different day-types will be supported: Weekday (Monday through Friday), Weekend/Holiday (Saturday, Sunday, or any NERC holiday).

- A previous event day is a day on which there was either a PDR event, a RDRR event, or an outage recorded in OMS. Previous event days are specific to PDR or RDRR. Charging a device used for MGO is not categorized as an event-day.[11]

The selection of days used in establishing G_{LM} is performed by iterating backward through the acceptable days prior to the event day. Once the target number of days is reached, selection ends. If the target number of days is not reached, but the minimum number of days is reached, the baseline is calculated on the selected days. The current target and minimum days used for the ISO Type 1 10-in-10 baseline methodology is as follows (again, to the extent possible the ISO proposal adheres closely to these existing rules):

- Weekday = 10 days target; 5 days minimum
- Weekend/Holiday = 4 days target; 4 days minimum

Example: If only 8 non-event days for a week day in the applicable event-day hour can be found across a 45-day look back, then those set of 8 hours in the non-event days will be averaged to determine the G_{LM}.

Generation devices with charging mode will use a value of 0 for those non-event days it is in "charging" mode during the qualified baseline period. If the minimum number of days is not reached, then $G_{LM} = 0$.

Option B3 – Load and Generation. Under this option both the load and the generation device would be registered in the PDR/RDRR resource and the demand response performance would be evaluated using a baseline (determined by N-G) and the physical meter G. The baseline B for the end-use load would be determined based on (N(t) – G(t)) calculations for comparable non-event days/hours resulting in a calculated value

[11] For reference, a detailed table specifying under which conditions a PDR or RDRR is considered to have an "event day" can be found on page 47 of the Demand Response User Guide located at http://www.caiso.com/participate/Pages/Load/Default.aspx.

for $DR_{LOAD}(t) = B_{N\text{-}G}(t) – [N(t) – G(t)]$ as previously described under option B1. The generation offset would be calculated as previously detailed under option B2 resulting in a calculated value $DR_{SUPPLY}(t) = – [G(t) – G_{LM}(t)]$.

The total performance evaluation under this option would be the combined demand responses attributed to $DR_{LOAD}(t)$ and $DR_{SUPPLY}(t)$, resulting in a total demand response reduction calculated as:

$$DR_{TOTAL}(t) = DR_{LOAD}(t) + DR_{SUPPLY}(t)$$

$$DR_{TOTAL}(t) = B_{N\text{-}G}(t) – N(t) + G_{LM}(t)$$

Example: Assume that $N(t) = 15$, $G(t) = - 7$, $B_{N\text{-}G}(t) = 25$ and $G_{LM}(t) = - 3$. The total performance evaluation would be :

$$DR_{LOAD}(t) = B_{N\text{-}G}(t) – [N(t) – G(t)] = 3$$

$$DR_{SUPPLY}(t) = – [G(t) – G_{LM}(t)] = 4$$

$$DR_{TOTAL}(t) = 7$$

PDR/RDRR cannot export energy during ISO dispatch intervals. The scheduling coordinator for the DRP is required to test its settlement quality meter data before submission to the ISO against the net export check described in Table 1. Specifically, the scheduling coordinator acting as the scheduling coordinator metered entity must ensure that for each sub-resource that makes up a PDR/RDRR aggregation, the facility meter "N" minus the output from the behind-the-meter device metered by "G" must be greater than or equal to zero. The ISO retains the authority to audit both the N and G meter data values submitted by the scheduling coordinator acting as the scheduling coordinator metered entity to ensure compliance against the no export rule as described in Table 1.

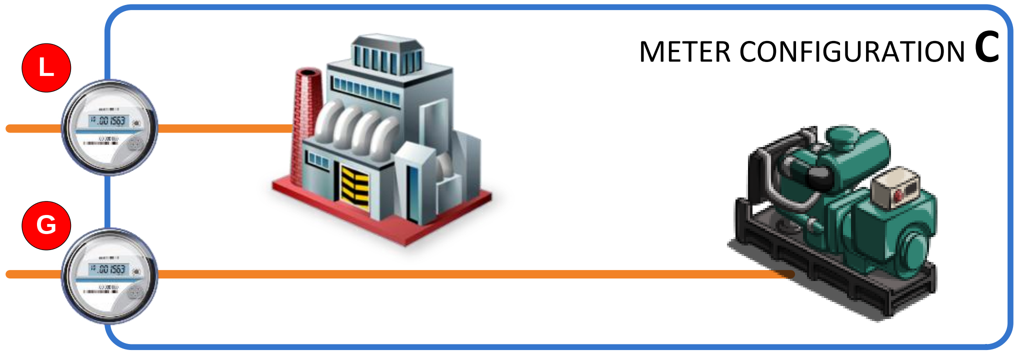
Table 1 below summarizes the ISO proposal for meter configurations A and B and the three options for configuration B.

Table 1

	Meter Configuration A	Meter Configuration B		
		B1 Load Only	B2 Supply Only	B3 Load & Supply
Demand Response Providers (DRP)	Single DRP	Single DRP	Single DRP	Single DRP
Resources	Single PDR/RDRR	Single PDR/RDRR	Single PDR/RDRR	Single DRP
Registrations	Net Facility	Load	Supply	(1) Load (2) Generation
Locations (SANs)	Net Facility	Load	Supply	(1) Load (2) Supply
Performance Evaluation Methodology	$BN(t) – N(t)$	$B_{N-G}(t) – N(t) + G(t)$	$G_{LM}(t) – G(t)$	$B_{N-G}(t) – N(t) + G_{LM}(t)$
Export Check	All Intervals $N \geq 0$	All Intervals $N - G \geq 0$	All Intervals $N - G \geq 0$	All Intervals $N - G \geq 0$

Lastly consider meter configuration C illustrated in Figure 4 below. Here it is assumed that the utility has provided a separate service account for the generator or device, leaving the load independently measured.

Figure 4



This meter configuration provides the same information as meter configuration B, only with N-G replaced by the physical meter L. However, this configuration is required if separate participants are managing the load and the generation independent of one another. Since the load is not combined or affected by the generator or device as in meter configuration B, the generator or device alone cannot be a PDR/RDRR; it must be a Non-Generator Resource (NGR) or a Participating Generator (PG). A summary of rules for Meter Configuration C is provided in Table 2 below.

Table 2

	Meter Configuration C	
	Load Only	**Generation Only**
Demand Response Providers (DRP)	Single DRP (May be different from generation owner)	Cannot be PDR/RDRR but would participate in the ISO market as a non-generator resource (NGR) or participating generator (PG).
Resources	Single PDR/RDRR	
Registrations	Load	

	Meter Configuration C	
	Load Only	**Generation Only**
Locations (SANs)	Load	
Performance Evaluation Methodology	ISO Type 1 Baseline (L)	

Current demand response system design accommodates a single performance evaluation method for a resource due to the current one registration to one resource limitation. There may be limitations imposed on stakeholders until such time that the system, and processes associated with its use, can accommodate many registrations to one resource. Subject to this limitation, the ISO proposal is to offer each of the following performance measurement options previously discussed.

Under PDR/RDRR, a resource and its underlying locations cannot export to the grid. Current metering business practice requires that the meter data submitted for the resource represents load at all locations. Therefore, the meter data for that location must be “zero” for any interval in which there is exporting of energy under meter configuration A and meter configuration B. Additionally, this will apply under meter configuration B for any interval where the output of the behind-the-meter generator or device exceeds the retail load at the location.

6.2.2 Baseline Type-II

The ability to use statistical sampling to estimate load meter data submitted to the ISO to evaluate the performance of an ISO dispatched demand response resource (PDR/RDRR) is described in section 10.1.7 of the ISO tariff:

> **10.1.7 Provision of Statistically Derived Meter Data**
>
> A Demand Response Provider representing a Reliability Demand Response Resource or a Proxy Demand Resource may submit a written application to the CAISO for approval of a methodology for deriving Settlement Quality Meter Data

> for the Reliability Demand Response Resource or Proxy Demand Resource that consists of a statistical sampling of Energy usage data, ***in cases where interval metering is not available for the entire population*** of underlying service accounts for the Reliability Demand Response Resource or Proxy Demand Resource. As specified in the Business Practice Manual, the CAISO and the Demand Response Provider will then engage in written discussion which will result in the CAISO either approving or denying the application. [emphasis added]

Stakeholders have asked for clarification on the definition of "interval metering is not available" as it pertains to the applicability of this option. The vast majority of residential and small-commercial customers have hourly interval metering installed that can provide interval data in a granularity that would support ISO day-ahead market participation but the availability of the data is in question by demand response providers. To participate in ISO real-time and ancillary services markets, a maximum of 15-minute interval metering is required as the ISO allows meter data to be created by parsing 15-minute recorded interval meter data into three equal 5-minute intervals per BPM for metering (see section 12.5). Hourly interval metering could not be used to meet this requirement for real time and ancillary service participation. In all ISO participation cases, revenue quality meter data (RQMD), as specified by the local regulatory authority (LRA), is required to create settlement quality meter data (SQMD) for ISO PDR and RDRR settlements. The ISO does not want to preclude participation of residential or small-commercial customers because this data is "unavailable" to meet either ISO required submittal timelines or granularity.

To expedite demand response participation in wholesale markets, including resource adequacy, the ISO is proposing to support the use of statistical sampling for real-time and ancillary services participation when interval metering installed at all underlying resource locations is not recorded in 5- or 15-minute intervals. The ISO believes this is supported by section 10.1.7 of the ISO tariff.

The ISO is not proposing to support the use of statistical sampling for day-ahead participation, when hourly interval metering is installed at all underlying resource locations but RQMD is not available or accessible to demand response providers or their scheduling coordinators, for all underlying locations, in the established timelines required to meet ISO SQMD submission timelines.

The ISO will continue to determine if this tariff section may need to be expanded to include circumstances when interval metering is installed at all underlying resource locations but RQMD is not available or accessible to demand response providers for wholesale market participation. However, the ISO has not received sufficient input or clarity from stakeholders on why tariff expansion is necessary given existing ISO settlement timeline and meter data submission requirements for PDR/RDRR.

There are two key dates for the submittal of the meter data per the ISO settlement timeline: (1) T+8B and (2) T+48B. For the T+8B meter data submittal, Section 10.3.6.2 of the ISO tariff states “Scheduling Coordinators can submit **Estimated** Settlement Quality Meter Data for Demand Reponses Resources” [emphasis added]. RQMD meter data is not a necessity at the T+8B submittal deadline and it is not clear to the ISO why RQMD would not be available by the T+48B meter data submittal date as required by Section 10.3.6.3 of the ISO tariff given today all load serving entities are submitting SQMD by T+48B, which could be made available to demand response providers under provisions approved by the CPUC.

The ISO is concerned with how this may conflict with the responsibilities of a scheduling coordinator to comply with standards established by the LRA and must further contemplate this expansion in relation to Section 10.3.7 of the Tariff which states:

> Each Scheduling Coordinator, in conjunction with the relevant Local Regulatory Authority, shall ensure that each of its Scheduling Coordinator Metered Entities connected to and served from the Distribution System of a UDC shall be metered by a revenue meter complying with any standards of the relevant Local Regulatory Authority or, if no such standards have been set by that Local Regulatory Authority, the metering standards set forth in this CAISO Tariff and as further detailed in the Business Practice Manuals.

Throughout this initiative, the ISO has invited stakeholder feedback on these ISO concerns and their relationship to the ISO extending the use of statistical sampling for customers with installed hourly interval metering, including stakeholders view on the necessity of such a tariff extension if RQMD is not available. To date, the ISO has not received convincing evidence to pursue tariff modifications to extend the statistical sampling provision applicability for day-ahead participation, when hourly interval metering is installed at all underlying resource locations.

The ISO recognizes the IOUs are expending considerable effort to accommodate the RQMD data needs of demand response providers in both the timelines and interval granularity required for wholesale market participation through multiple CPUC proceedings including Customer Data Access and Rule 24. The ISO will re-visit the applicability proposed upon implementation of resulting technical and process solutions that solves either one or both unavailability issues identified by participants. The ISO also proposes to define the use of ISO Type 2 to derive SQMD from a sample based on using RQMD, collected at the required interval granularity, for all customers identified in the sample set.

Finally, the ISO Type 2 proposal is intended to be used, and its use will be identified as such, for a demand resource participating under PDR and RDRR. Any other use of ISO Type 2 to derive SQMD for any other form of ISO participation under this proposal would be prohibited.

The ISO tariff provision to statistically derive meter data was included to accommodate participation of an aggregated PDR/RDRR comprising several locations, some of which are interval metered and have revenue quality meter data available, and with the condition that the balance of locations would mimic the metered random sample. Once the randomly sampled fraction of revenue quality meter data is converted to settlement quality meter data (SQMD), the sum is then scaled to derive the SQMD sized for the PDR/RDRR. This scaled SQMD value is termed the **Virtual** SQMD and is calculated as:

$$m_{VIRTUAL} = \frac{N}{n} \cdot \sum_{i=1}^{n} m_i$$

where: $N = Total\ Number\ of\ Locations\ Participating$

$n = Number\ of\ Metered\ Locations$

$m_i = SQMD\ for\ Location\ i$

$n \in N\ (Metered\ Locations\ are\ a\ subset\ of\ Locations\ Participating)$

It is critical that the members of the sample (n) be selected at random from within the population (N). This means that sample members be selected with no bias to any factor such as size, location, or customer type. The participant may be required to demonstrate that each PDR/RDRR sample was selected at random.

Determining the minimum number of metered locations providing RQMD is based on statistical sampling principles. For an infinite population, the required sample size is given as:

$$n' = \left(\frac{z}{e_{REL}}\right)^2 \cdot \left(\frac{1-p}{p}\right)$$

Where: $e_{REL} = Relative\ Precision\ Level$

$z = Value\ based\ on\ Level\ Of\ Confidence$

$p = True\ Population\ Proportion$

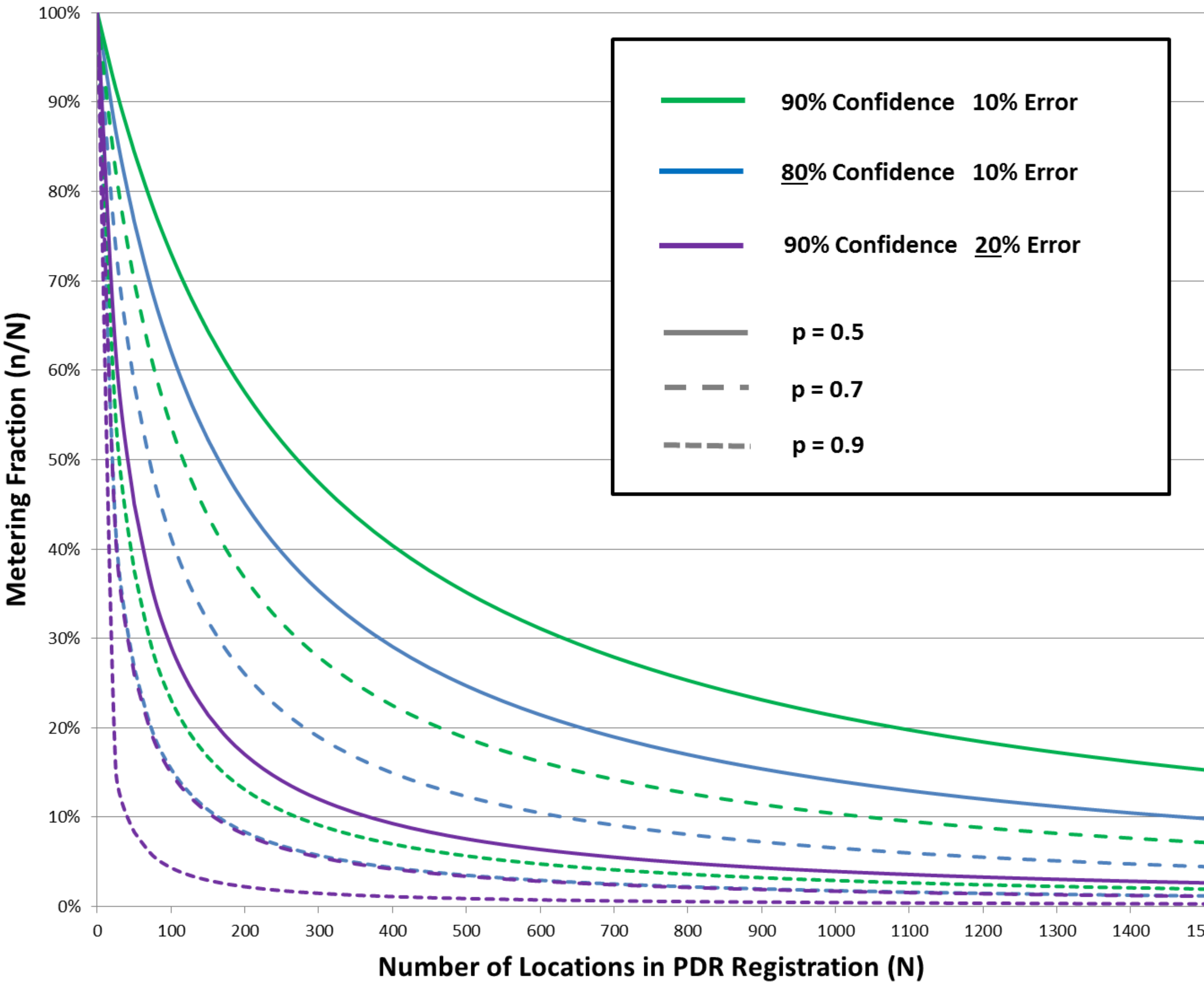
Many ISOs and RTOs use this formulation. The following table summarizes some samples:

	Relative Precision Level	Level Of Confidence
PJM	10%	90% (z=1.645)
ISO New England	10%	80% (z=1.282)
NYISO	10%	90% (z=1.282)

For a finite population, the sample fraction can be calculated as:

$$\frac{n}{N} = \frac{n'}{N + n'}$$

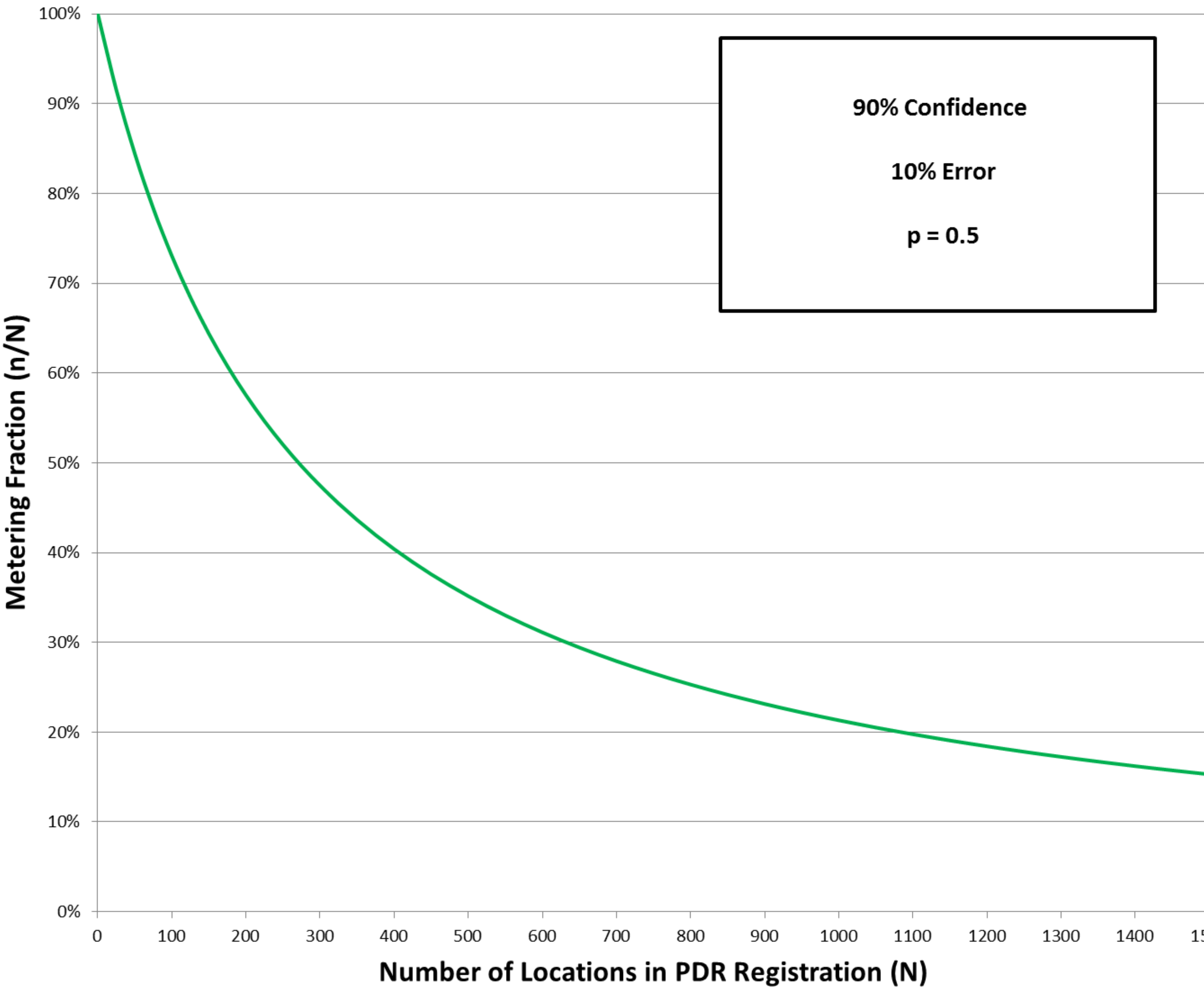
This yields several different Metering Fraction curves as a function of the two variables to be fixed,in addition to the population size (N) and the True Population Proportion (p) as shown on the following page:



90% Confidence 10% Error
80% Confidence 10% Error
90% Confidence 20% Error
p = 0.5
p = 0.7
p = 0.9
Metering Fraction (n/N)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
Number of Locations in PDR Registration (N)

The following figure shows the resulting curve based on the ISO's decision to set the Relative Precision Level to 10% and the Level of Confidence to 90%, which results in a z of 1.645 [12]. Since the True Population Proportion is difficult to calculate, a value of p = 0.5 is chosen, similar to other ISOs and RTOs. The sample size for an infinite population with these requirements is therefore: $n' = 271$.

[12] The value of z is derived from a distribution of samples with 10% of the high samples and 10% of the low samples in the two respective tails of a Gaussian distribution.



90% Confidence
10% Error
p = 0.5
Metering Fraction (n/N)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
Number of Locations in PDR Registration (N)

The ISO proposes to require that every resource employing ISO Type 2 have a sample fraction:

$$f = \frac{n}{N} = \frac{n'}{N + n'} = \frac{271}{N + 271}$$

The following table shows a number values for the fraction based on the number of locations:

PDR Locations	Minimum Sample Fraction
10	96%
25	92%
50	84%
75	78%
100	73%
125	68%
150	64%
175	61%
200	58%
250	52%
300	47%
350	44%
400	40%
500	35%
750	27%
1000	21%
1500	15%
2000	12%

Should the size of the population increase or decrease over time, the sample fraction must be reevaluated and the sample size adjusted accordingly. Except for the scheduling coordinator submitting SQMD for a derived virtual metering data based on statistical sampled physical metering rather than physical metering data for all locations, a PDR/RDRR utilizing ISO Type 2 provisions (NAESB Baseline Type-II) is treated identical to NAESB Baseline Type-I from an ISO demand response system processing perspective.

Market participants with aggregated PDR/RDRRs may be requested to comply with ISO information requests to audit the meter data collection process and the virtual meter scaling process should it deem that the data being submitted is questionable.

As a final note, a long-standing ISO philosophy regarding PDR and RDRR is to focus initial implementations on features that achieve as many of the business goals as practical while keeping the processes simple and rules straight-forward. As this applies to allowing for statistical sampling of meter data (ISO Type 2), the CAISO position is to formalize a well-defined and easy-to-understand rule that applies to all market participants as outlined in this proposal. This proposal is consistent with other markets, and errs on the side of a more conservative approach.

Through this initiative the ISO has received several promising ideas and as experience is gained with this model we fully expect to continue working with stakeholders to further enhance ISO Type 2. Future rules the ISO would like to revisit include, but are not limited to, additional logic that would allow for a sampling method that may be biased by existing installations of 15-minute interval data meter equipment and a process for demonstrating that PDR/RDRR constituent locations are more homogenous than average in order to qualify for a smaller sampling fraction.

From an implementation standpoint, the current ISO demand response registration system (DRRS) redesign scope does not contain specifications that can automatically calculate the MGO variations being considered above. All ISO Type 1 calculations for the load portion of the above scenarios (when applicable) will be done by the new DRRS system. All “supply” calculations for the resource behind the meter will be done by the scheduling coordinator and be inputted into the system by the scheduling coordinator.

7 Non-resource adequacy (non-RA) multiple-use applications

7.1 Background

Multiple-use applications are those where an energy resource or facility provides services to and receives compensation from more than one entity. The ISO, CPUC and Energy Commission 2014 Energy Storage Roadmap identified "Define and develop models and rules for multiple-use applications of storage" as a medium-priority action item. The present initiative addresses two broad categories or types of multiple-use applications that the Energy Storage Roadmap identified for storage and extends them here to include more general DER aggregations (DERA): (1) the DERA provides reliability services to the distribution grid and services to the wholesale market; and (2) the DERA provides services such as demand management to end-use customers while participating in the wholesale market.

Consistent with previous papers issued as part of this initiative, the treatment of these multiple-use applications is limited to circumstances where the resource either is not providing resource adequacy (RA) capacity or can set aside a portion of its installed capacity not providing RA capacity. The criterion "not providing RA capacity" is intended to apply on a monthly basis for purposes of this initiative; i.e., the capacity in question that capacity is not included in a load-serving entity's RA plan for the given month.

7.2 Assumptions underlying this draft final proposal

The first assumption is that ESDER should follow the DERP[13] proposal regarding multi-pricing node (pnode) DER aggregations. In the DERP the ISO is proposing to relax the

[13] "DER provider" or "DERP" refers to an entity that aggregates individual DER sub-resources to create an aggregate resource called a "DER aggregation" or "DERA" for participation in the ISO markets. The DERP initiative, which was approved by the ISO Board of Governors in July 2015, will create a pro forma "DERP agreement" or "DERPA" that will be the contractual relationship between the DERP and the ISO. The ISO is currently preparing draft tariff language for the DERP initiative to be filed at FERC.

original requirement for multi-pnode DERAs that (a) all sub-resources must be of the same type and move in the same direction in response to an ISO dispatch of the DERA. The ISO is proposing instead to impose the requirement – which has been the underlying concern all along – that (b) the net movement or net response at each pnode must be in the same direction as the dispatch and in alignment with the distribution factors (DFs) used in the dispatch. Under requirement (b) the ISO will not require the underlying sub-resources to be of the same type, or even that they all move in the same direction, but only that the net response of all sub-resources at each pnode that comprises the DERA be in the direction of the dispatch and in the same relative proportions as the DFs. Moreover, the SC for the DERA may bid the DFs in each hour, so the DFs need not be fixed. But whatever DFs the SC bids for the DERA will be used in the dispatch, so the ISO will expect the resource to move in accordance with the bid DFs if it is dispatched.[14]

The second assumption is that the ISO will require settlement quality meter data (SQMD) from the SC for a DERA, to be submitted on a daily basis following ISO submittal timelines, and will settle the DERA based on that SQMD, for all market intervals, not just those intervals in which the DERA was issued an ISO schedule or dispatch instruction.[15] PDR and RDRR resources will continue to have the ability to provide SQMD and be settled through the ISO market only for intervals in which they were dispatched by the ISO, but resources participating under the DERP construct will not.

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[14] In response to stakeholder requests for additional explanation and illustrative examples regarding the proposed change just described, the ISO has developed a supplement to the draft final proposal in the DERP initiative, which may be found at http://www.caiso.com/informed/Pages/StakeholderProcesses/ExpandingMetering-TelemetryOptions.aspx

[15] A multi-pnode DERA will be settled at an aggregated pnode (APnode) price that is the average of the pnode prices at pnodes included in the DERA, weighted by the distribution factors (DFs) for the DERA that either were submitted by the SC in the bid for the relevant interval or are on file as default DFs for intervals in which the SC does not bid DFs.

7.3 Draft Final Proposal – ISO's proposed positions on questions posed in this initiative

Type 1. DER provide services to the distribution system and participate in the wholesale market

<u>Question 1:</u> If a DER is procured by the distribution utility to provide a grid service and bids into the ISO market, how should conflicting real-time needs of the distribution utility and the ISO be managed?

<u>Draft Final Proposal:</u> The ISO proposes to settle a DER dispatch in the same manner as other generating resources are settled. If the DER deviates from an ISO dispatch instruction to provide service to the distribution system or for another reason, its deviation will be settled as uninstructed imbalance energy.

Stakeholders generally support this approach, and the ISO agrees this approach is appropriate for DER capacity not serving as RA capacity. In the 2016 phase of ESDER when we consider DER capacity that is subject to RA offer obligations, we will explore what modifications to this approach may be appropriate for RA resources.

<u>Question 2:</u> Is there a concern about double payment to a DER for any market interval in which the DER follows an ISO dispatch instruction that aligns with the service the same DER is providing to the distribution utility? If so, how should the ISO address this concern?

<u>Draft Final Proposal:</u> The ISO proposes not to implement any provisions at this time to address potential double payment situations where a DER is compensated by the distribution utility and is also settled through the ISO market for responding to an ISO dispatch or for UIE. The ISO may reconsider this position in the future, but for now the issue is not yet ripe for resolution because distribution-level services have not yet been defined. The ISO's position is that concerns about double payment from both the distribution utility for distribution-level services and the ISO for market participation need to be based on an understanding of the specific distribution-level services involved and how they are procured, utilized and compensated by the distribution utility. These questions are being considered in CPUC proceedings[16] and may or may not be ripe for consideration by the ISO in the 2016 ESDER initiative.

Question 3: Should there be limitations on the provision of distribution-level services by a multi-pnode DER aggregation or the sub-resources of a single-pnode or multi-pnode DER aggregation that is an ISO market participating resource? If so, what limitations are appropriate?

Draft Final Proposal: The ISO proposes not to impose any such limitations. This follows the first assumption described in section 7.2 above regarding the provisions for DER aggregations (DERA) that will be filed at FERC in the near future. Specifically, under the DERP proposal, the ISO will not require any specific performance by sub-resources that comprise either a multi-node or single-note DERA. The requirement is that when the ISO issues a dispatch instruction to a DERA, the net response at each constituent pnode be in the direction of the dispatch and that the net responses across constituent pnodes be in proportion to the distribution factors for the DERA. As long as the DERA complies with this requirement, the operational behavior of individual sub-resources will not be subject to ISO requirements. Thus an individual sub-resource could respond to the needs of the distribution system as long as the DERP who operates the DERA delivers the net response at the associated pnode that is in the same direction as the dispatch instruction and aligns with the distribution factors for the DERA.

Type 2. DER provide services to end-use customers and participate in the wholesale market

Consistent with the Revised Straw Proposal, the ISO does not believe there are issues that need to be addressed at this time on this topic, beyond the issues being addressed under the PDR/RDRR topic. The PDR/RDRR topic in this initiative deals with scenarios where DER provide services to end-use customers and participate in the wholesale market. The ISO believes that those elements of the present initiative should be resolved, at which time we can better assess whether there are additional issues regarding this category of multiple-use applications that were not addressed and should be included in the 2016 ESDER scope.

[16] See in particular the CPUC Distribution Resources Plan (DRP) proceeding (R.14-08-013) and the Integration of Distributed Energy Resources (IDER) proceeding (R.14-10-003).

7.4 Responses to stakeholder comments

<u>Stakeholder comment:</u> One theme many stakeholders raised was the desire for rules that allow a resource to choose not to participate in the ISO markets in all hours. Stakeholders propose that the SC for the resource could choose to submit a bid only for hours when the resource wants to participate, and for other hours the resource would have no obligation to participate and would not be settled by the ISO for its activity during those hours. The ISO would settle the resource's performance only for hours in which the ISO issued the resource dispatch instructions, not for hours the SC submitted a bid for the resource and it was not dispatched.

<u>ISO response:</u> Only resources using the PDR or RDRR model have this flexibility today. Under the NGR model or other models for DERA participation, the resource is subject to all the normal provisions that apply to resources in the ISO markets. In particular, although a DERA is able to be a scheduling coordinator metered entity (SCME), it will be required to provide SQMD in accordance with ISO submittal timelines and will be subject to ISO settlement for all hours regardless of whether it submitted a bid and was dispatched. The ISO will not revisit this requirement on NGR in the 2105 ESDER scope, but recognizes that there is wide support among stakeholders for a variant of NGR that allows the resource to elect when to participate in the wholesale market and be settled accordingly, and will consider including this in the 2016 scope of the ESDER initiative.

Type 1. DER provide services to the distribution system and also participate in the wholesale markets.

Question 1: Conflicting real-time needs

<u>Comments:</u> Most stakeholders support relying on uninstructed imbalance energy (UIE) settlement for deviations of the resource from ISO dispatch. For hours where the SC does submit a bid and the ISO dispatches the resource, the resource would be settled in the normal way based on its response to the ISO dispatch, with deviations from the dispatch – for example, in cases where the resource responded instead to a distribution system need – settled as UIE.

<u>ISO response:</u> The ISO agrees and proposes to use the UIE settlement provisions for deviations from DERA schedules and ISO dispatches. UIE settlement will also apply to intervals where the DERA operates without an ISO schedule or dispatch.

Type 2. DER provide services to end-use customers and participate in the wholesale market.

Comments: Several stakeholders commented on the need to expand the capabilities under the PDR model to allow bi-directional ISO dispatch (i.e., a dispatch instruction to increase consumption, for example to relieve excess supply on the grid) and to provide regulation service, as long as the resource satisfies the PDR requirement not to export energy across the end-use meter onto the distribution grid.

ISO response: In the 2015 scope the ISO cannot address any modifications to the PDR model other than the topics already in scope of this initiative. Modifications such as those suggested in the comments will be considered as potential topics for the 2016 ESDER initiative.