Straw Proposal

For the Design of Proxy Demand Resource (PDR)

And

Impacts of Direct Participation

March 5, 2009

Design of PDR and Direct Participation

Table of Contents

Acronyms used in this proposal

TLA	Description	TLA	Description
ARC	Aggregator of Retail Customers	LSE	Load Serving Entity
CAISO, or ISO	California Independent System Operator	M&V	Measurement & Verification
CPUC	California Public Utility Commission	MAP	Markets & Performance
CSP	Curtailment Service Provider	MRTU	Market Redesign & Technology Upgrade
DR	Demand Response	NOPR	Notice of Proposed Rulemaking

ESP	Electric Service Provider	PL	Participating Load
FERC	Federal Energy Regulatory Commission	RTO	Regional Transmission Operator
ISO	Independent System Operator	SC	Scheduling Coordinator
LPPC	Large Public Power Council	TAPS	Transmission Access Policy Study Group

1. Introduction

This Straw Proposal is part of the California ISO's (the ISO) efforts to enhance the demand response (DR) functionality that will exist at MRTU start-up and to address new FERC requirements for demand response due to the issuance of Order 719 by the Federal Energy Regulatory Commission (FERC).[1] The Proxy Demand Resource (PDR) market design enhancement is one of two DR models the ISO is proposing to implement by summer 2010. This paper explains the PDR product and how the PDR design is consistent with FERC Order 719.[2]

Significant to the design of PDR, FERC Order 719 requires that ISOs permit a DR aggregator to bid demand response on behalf of retail customers into the organized energy markets. The ISO and its stakeholders use the term "direct participation" to convey this concept of a DR aggregator bidding DR resources directly into the ISO's wholesale electricity markets. The focus of this Straw Proposal is to convey the ISO's proposed PDR market design enhancement where there is the express ability for DR aggregators to bid DR resources on behalf of retail customers directly into the ISO's markets, where permitted by the applicable local regulatory authority.

Prior to Order 719, the ISO was preparing recommendations to take to its Board of Governors concerning design enhancements that would enable DR to participate in the wholesale markets, including accepting bids from DR resources for ancillary services comparable to any other AS capable resources, and allowing DR resources to specify certain limits with their bids such as frequency, duration, and the amounts when offering ancillary services.[3] With Order 719, the ISO had to reconsider elements in its originally proposed DR market design to consider the effects and impacts of Direct Participation on those designs.

To initiate what impacts Direct Participation would have on the ISO's proposed design enhancements that were already in progress, the ISO published an Issue Paper on Direct Participation on December 22, 2008.[4] The purpose of the Issue Paper was to identify readily apparent issues and invite stakeholders to identify additional issues or impacts that the ISO should consider in its proposed market design enhancements in order to comply with Order 719. The ISO discussed its Issue Paper at a stakeholder conference call and stakeholder meeting on January 5, 2009 and January 15, 2009, respectively, and invited stakeholders to identify additional issues. These materials, and stakeholder comments related to the Issue Paper, are available at http://www.caiso.com/1893/1893e350393b0.html.

This Straw Proposal is the next formal step in the ISO's stakeholder process, and presents the ISO staff's analysis of the issues that have been identified concerning the new FERC requirements, and preliminary proposals for resolving the issues in the context of the proposed DR market design enhancements. This document will be discussed with stakeholders and the ISO's Market Surveillance Committee and additional comments from stakeholders will be solicited. The ISO will then prepare its Draft Final Proposal, which will describe what the ISO staff sees as its proposed final, comprehensive set of market enhancements in light of FERC's requirements. The ISO will

---

1 FERC Final Rule re Wholesale Competition in Regions with Organized Electric Markets (125 FERC ¶ 61,071) (issued in Docket Nos. RM07-19-000 and AD07-7-000 on October 17, 2008) (hereinafter "FERC Oct 17 Final Rule"). Appendix A to this document summarizes the relevant sections of Order 719 pertaining to the direct participation by ARCs.

2 The other model is called Dispatchable Demand Response (DDR), which has been discussed with stakeholders, but is not a focus in this Straw Proposal

3 These market design enhancements are more fully described in Section 2 of this document.

4 The ISO defines "Direct Participation" as the ability for end-use customers or Aggregators of Retail Customers (ARCs) to offer DR resources into the ISO's wholesale electricity markets, through a Scheduling Coordinator, assuming all established requirements and regulations of the ISO and of the Local Regulatory Authority have been met and any required coordination with the load-serving entity satisfied. Direct Participation allows DR to be bid directly into ISO markets as a unique resource, separate and distinct from the Load-Serving Entity (LSE) submitting the overall load schedule.

again solicit and consider stakeholder comments on the Draft Final Proposal. This process is discussed further in Section 4 of this document.

2. Development of Demand Response Enhancements

The ISO has been working on enhancements to its Market Redesign and Technology Upgrade (MRTU) market design to enable greater DR participation in its markets through the development of two new Demand Response products which are Dispatchable Demand Resource (DDR) and Proxy Demand Resource (PDR). Both products serve different needs within the Demand Response market. Features and requirements from Order 719 will be incorporated into the design of these new products and aspects of each will continue to be vetted through the stakeholder process which is planned to be completed by August 2009.

At start-up of MRTU, limited functionality will exist that will allow Participating Load to participate in the Day-Ahead energy and Non-Spinning Reserve Market and allow potential dispatch in the RT energy market for capacity that is awarded as non-spinning reserve in the DA market.[5] This limited functionality is an interim measure to allow Participating Load to participate in the wholesale markets until the implementation of DDR and PDR which is planned for implementation within 12 months after MRTU start-up.

The ISO plans to integrate Direct Participation into the DDR and PDR products, which will enable a DR aggregator, or commonly referred to as a Curtailment Service Provider (CSP), to directly bid DR resources into the organized wholesale electricity markets. It is important to recognize that the DDR and PDR market design enhancements build on Participating Load functionality that will exist at MRTU start-up, which, in turn, is based on a Participating Load capability that has existed since the ISO first began operation in 1998. The ISO previously established many details of how PL functions as part of the ISO markets, and this Straw Proposal does not seek to reinvent what is already in place. The DDR and PDR products enable more flexible participation of DR, and the Direct Participation element recognizes the addition of a new type of market participant, i.e. the Curtailment Service Provider.

Because of the scope of the changes related to Direct Participation, the ISO anticipates initially supporting Direct Participation as part of the PDR model, and then extend it to DDR, as appropriate, after experience using the PDR model. Also, as the ISO gains experience under its MRTU market structure, it may identify opportunities for further removal of barriers to DR.

2.1. Description of Proposed Demand Response Products

Dispatchable Demand Resource (DDR)

The Dispatchable Demand Resource treats a demand resource most analogous to a supply-side resource and is scheduled and settled at a node or custom aggregation of nodes, often referred to as a Custom Load Aggregation Point or Custom LAP (CLAP). The DDR product enhances the

5 MRTU Release 1 also includes a manual process for adjusting the procurement in the Residual Unit Commitment (RUC) process for demand response that is not scheduled as Participating Load. The ISO anticipates continuing to support this process as long as there are recognized demand response programs that are activated in the day-ahead market timeframe but not scheduled as Participating Load.

MRTU Release 1 functionality for Participating Load by modeling extensive operational characteristics such as maximum duration of dispatches, maximum number of dispatches per day, and maximum amount of electric energy reduction, as well as enabling the ability to provide all ancillary services and energy, including non-spinning reserve, spinning reserve, regulation, RUC capacity, Day-ahead energy and Real-time imbalance energy. In addition, DDR will have the option to submit three part bids into the ISO markets that will enable these demand to be optimized in the ISO's Day-Ahead and Real-Time markets, the same as a generator. Both scheduling and settlement will take place at a CLAP that the ISO establishes for the specific PL resources, as required by FERC's September 21, 2006, decision conditionally approving the MRTU market design and implemented at MRTU start-up.[6]

DDR will meet the needs of aggregated pumps that participate in the ISO markets today as well as demand response that is located at a single node or at a collection of nodes that can be aggregated, forecasted and bid at a CLAP. The ISO believes the DDR model will work well for demand resources that operate over many hours of the year, including dynamic thermal energy storage, industrial process control, etc. In addition, the ISO intends to allow PL resources to supply Regulation as an ancillary service, and Regulation requires the ISO's Energy Management System (EMS) to monitor the participating customers' demand more closely than is likely to be provided through the PDR model.

The design for DDR was developed through stakeholder meetings in 2007 – 2008 and will be further enhanced to accommodate direct participation requirements. The Draft Final Proposal on DDR entitled "Draft Final Proposal for Post-Release 1 MRTU Functionality for Demand Response" may be found at the following link on the ISO website:

http://www.caiso.com/2070/2070c79e59140.pdf

The Presentation on Post-Release 1 MRTU Functionality for Demand Response is located at:

http://www.caiso.com/2074/2074e67d2a600.pdf

DDR is planned for implementation within 12 months of MRTU start-up.

Proxy Demand Resource (PDR)

Proxy Demand Resource (PDR) provides a simplified mechanism for DR resources to participate in the ISO's markets, with most of the same functionality available as in the DDR model, but without the requirements of creating the custom load aggregations that is used for the DDR product. The proposed PDR product was developed based on feedback from market participants that the Participating Load functionality available at MRTU start-up and the DDR product did not provide flexibility needed to incorporate price responsive Demand Response programs into the ISO markets. Specifically, the PDR Product addresses the following challenges:

- for retail DR programs that are embedded as part of the Investor-Owned Utility's (IOU) load (aka non-Participating Load) it is difficult to anticipate and coordinate the MW quantity of DR

[6] Day-ahead scheduling of the demand of Participating Loads in MRTU Release 1 uses Custom Load Aggregation Points (Custom LAPs or CLAPs), which may consist of loads at single nodes or an aggregation of multiple loads at nodes within a Local Capacity Area as defined for Resource Adequacy requirements. Scheduling and settlement of PL using CLAPs is not a new requirement imposed by the DDR model's enhancements to the Release 1 PL functionality.

expected from the price-responsive DR programs before the ISO's Day-ahead market runs and to factor this quantity into the ISO's RUC procurement target.

- for retail DR programs it can be challenging to develop demand forecasts for scheduling purposes, down at the CLAP level, necessary to support DR programs that may have frequent customer enrollment changes from month to month.

Thus, an important distinction between DDR and PDR is that, different from the DDR model, PDR doesn't require the underlying load associated with the DR resource or program to be uniquely forecast and scheduled at the CLAP level. Instead, the load associated with the PDR resource is embedded with all the other load that is scheduled by a load-serving entity, at the Default LAP level, while the unique DR bids represent price-responsive demand within specific local Sub-LAPs[7] or at a CLAP. The ISO recognizes that management of the data required for scheduling CLAPs may be difficult for DR resources that aggregate numerous small end-use customers, with frequent migration, i.e. enrollments and de-enrollments in a DR program. Therefore, the ISO will allow market participants to designate their DR resources as located in an ISO defined Sub-LAP and the ISO will use standard distribution factors as an alternative to maintaining CLAPs, for the purpose of dispatching DR resources.

The proposal for PDR was developed jointly by the ISO and a stakeholder formed working group which consisted of a cross-section of representatives from the utilities, DR aggregators, customer representatives, electric service providers and the California Public Utilities Commission.[8]

PDR is planned for implementation by May 2010.

3. Proposal for Proxy Demand Resource (PDR)

3.1. Background

For reasons described above, the PDR model is intended to make it easier to administer end-use customer participation, and lessen the coordination requirements of forecasting, scheduling and curtailing load within CLAPs by separate entities, i.e. the Curtailment Service Providers and the Load Serving Entities.

In the January 15th Stakeholder Meeting, three options for the design of PDR were presented to market participants. Those options included:

1. PDR Option 1

   Under the PDR 1 proposal, the bid to curtail load is submitted by the CSP using a proxy generator at the CLAP and the LSE schedules their load at the Default LAP. The LSE's Day-Ahead schedule is adjusted based on the quantity of the cleared Day-Ahead bid to curtail submitted by the CSP. Therefore, the LSE is getting paid implicitly the Day-Ahead price for that curtailed load that cleared the Day-Ahead Market. Bids to curtail load that clear the Real-Time Market are settled as uninstructed Deviation with the LSE. The CSP receives no direct settlement from the ISO under PDR option 1 and there is no baseline methodology employed by the ISO to determine performance of the curtailed load.

7 A ISO defined set of PNodes within a Default LAP sued for CRR allocation and CRR auction

8 Specifically, the stakeholder formed working group consisted of representatives from PG&E, SCE, SDG&E, the CPUC, Enernoc, AReM, EUF and CMTA.

2. PDR Option 2

PDR Option 2 has the same characteristics as Option 1 with the exception that there is no adjustment made to the LSE's Day-Ahead Schedule for the cleared Day-Ahead bid to curtail load submitted by the CSP. Therefore all curtailed load is settled as uninstructed deviation with the LSE. This option was added to eliminate the need to establish a link between the CSP and LSE in the ISO's settlement system so that the ISO could adjust the LSE's Day-Ahead schedule by the CSP's cleared Day-Ahead PDR bid. Again, under this option, the CSP receives no settlement from the ISO and there is no baseline methodology employed by the ISO to determine performance of the curtailed load.

3. PDR A

Similar to the other two proposals, under the PDR A proposal all PDR bids to curtail load are submitted by the CSP at the CLAP and the LSE schedules their load at the Default LAP. The key differences with the PDR A proposal as compared to the other two options are that all settlement for curtailed load is directly with the CSP rather than with the LSE and performance of the curtailed load is determined through a baseline calculation. The LSE's Day-Ahead schedule is adjusted for both Day-Ahead and/or Real-Time curtailed load based on the performance of the CSP's curtailed load as measured by the baseline.

Table 1 below illustrates a simple example of the three PDR options. The example assumes a single LSE to a single CSP and perfect compliance by the PDR resource. Additional examples that illustrate the three PDR options discussed are posted on the ISO website at:

http://www.caiso.com/2360/23608821fc90.xls

The assumptions for this example are as follows:

- LSE schedules 10 MW of Load in the Day-Ahead Market
- CSP clears 1 MW of load reduction in Day-Ahead and another 1 MW of load reduction in Real-Time
- Perfect compliance by PDR resource

Table 1 – Example of Basic Scenario for Three PDR Options

	PDR 1	**PDR 2**	**PDR A**
LSE Day-Ahead Demand Schedule			
LSE Cleared Day-Ahead Schedule	10	10	10
Adjustment	-1		
Adjusted Schedule for Day-	9	10	10

Ahead Energy			
CSP's Operation in Day-Ahead Market			
CSP's Cleared Demand Bid Day-Ahead	-1	-1	-1
Settlement to CSP			-1
CSP's Operation in Real-Time Market			
Cleared demand reduction Real-Time	-1	-1	-1
Settlement to CSP			-1
LSE Final Metered Demand			
Meter Read	8	8	8
Settlement to LSE			
Uninstructed Deviation	-1	-2	See Below
Calculation of UIE for PDR A			
LSE's Original Day-Ahead Schedule			10
Actual PDR (Baseline – Meter Reads)			-2
LSE Adjusted Day-Ahead Schedule			8
Actual Meter Read			8
Uninstructed Deviation			0

3.2. Pros and Cons of Three PDR Options

Table 2 summarizes the Pros and Cons identified by the working group for each of the three PDR design options[9].

	PDR 1	PDR 2	PDR A
Positives	▪ LSE paid Day-	▪ Easiest for the ISO	▪ DR dispatched at

[9] This is a summary of the Positives and Negatives and not a complete list of what was compiled in the working group meetings

	Ahead price for Day-Ahead DR ▪ No baseline resulting in simple implementation for ISO ▪ Settlement flexibility between CSP and LSE ▪ PDR impacts the LMPs	to implement due to no baseline and no settlement impact ▪ No linkage needed between CSP and LSE for purpose of settlements ▪ Settlement flexibility between CSP and LSE	CLAP and paid CLAP price ▪ Day-Ahead DR dispatch receives Day-Ahead price ▪ Motivates DR to high priced CLAPs ▪ Measurable and reportable performance of DR due to baseline ▪ DR benefits accrue to CSP rather than LSE
Negatives	▪ CSP has no obligation to perform ▪ CSP benefits accrue to benefit of LSE ▪ Need to allocate PDR specifically to each LSE to allow for adjustment of LSE DAM Schedule ▪ Motivates DR to low price CLAPs ▪ Dispatch price (CLAP) and settlement price (DLAP) at different location .	▪ CSP has no obligation to perform ▪ CSP benefits accrue to benefit of LSE ▪ Motivates DR to low priced CLAPs ▪ Day-Ahead DR settled at Real-Time price ▪ DR is not measurable and can get lost in Uninstructed Deviation	▪ Linkage between LSE and CSP needed for settlement same as PDR 1 ▪ ISO managed baseline adds complexity to implementation and policy ▪ Gaming concerns per LECG Money Machine (Load at DLAP and PDR @ CLAP) ▪ Meter data required at customer level for ISO settlement

One of the key issues that came out of the January 15th ISO stakeholder meeting was that the ISO needed to quickly narrow down the PDR options. In order to meet this objective, the ISO worked with the existing stakeholder working group that originally developed the PDR A proposal to help refine and develop a consensus PDR proposal. The working group created examples for all three PDR options, determined pros and cons of each, discussed gaming concerns and settlements impacts. Based on these working group efforts, the ISO and the stakeholder working group came to the consensus that PDR A is the proposal that is the closest to what FERC Order 719 intends.

PDR A will hereby be referred to as PDR for the remainder of this document.

3.3. PDR Functionality

PDR-based demand response is the combination of load that is scheduled by the LSE using the Default LAP (DLAP) and a bid to curtail submitted by the CSP using a separate proxy generator resource identifier bid at the Custom LAP (CLAP).

Demand Response participating as PDR may be bid into the Day-Ahead Market (DAM), the Real-Time Energy Market (RTM) and/or the Day-Ahead and or Real-Time Non-Spinning Reserve Market at a CLAP where the configurations may be as small as a PNode, or as big as a defined Sub-LAP or Local Capacity Area. The PDR design does not support PDR submitting an availability bid into the RUC market; however, the cleared Day-Ahead schedule on the Proxy Generator associated with the PDR will directly impact the RUC procurement target like any other scheduled generator in the Day-Ahead market.

PDR Bids to curtail load will be submitted to the ISO as if the PDR were a generator, using all of the same conditions and attributes set by the ISO for a generator's market participation.

In accordance with requirements defined in FERC Order 719, the LSE and the CSP may be the same entity or different entities and a bid to curtail submitted by a CSP may include load served by multiple LSEs.

The settlement for the curtailed portion of the load would be settled by the ISO directly with the CSP at the PDR's specified CLAP, based on the LMPs of the PNodes that make up that PDR's CLAP. Determination of actual PDR delivery would be derived from measurement of aggregate meter usage, calculated from a pre-determined baseline.[10] Verified performance against the baseline would determine the energy settlement with the CSP at the CLAP.

In accordance with this process, bids to curtail load that clear the Day-Ahead and/or Real-Time Market will appear as a reduction to the LSE's Day-Ahead Load Schedule for the purpose of settlement of uninstructed deviation. This is the only adjustment affecting LSE operations and its settlements processes with the ISO. There may be meter-to-cash impacts between the LSE and the retail participant due to DR resource participation in the wholesale markets. Otherwise, the LSE's Load is unaffected by the participation of DR resources in the ISO markets.

3.4. Illustrative Examples of PDR

Consider a specific Sub-LAP where there are two Local Capacity Areas. This is illustrated in the diagram below.

[10] This established baseline will be developed in discussions with market participants through the ISO stakeholder process

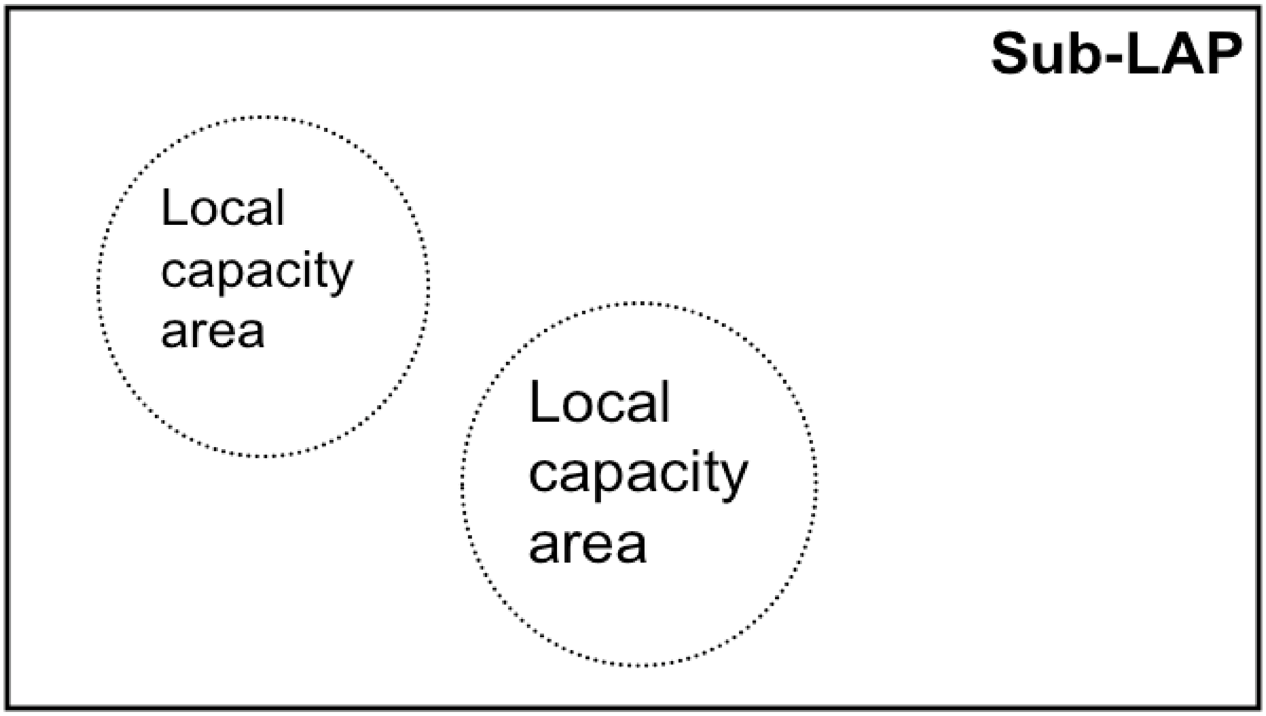
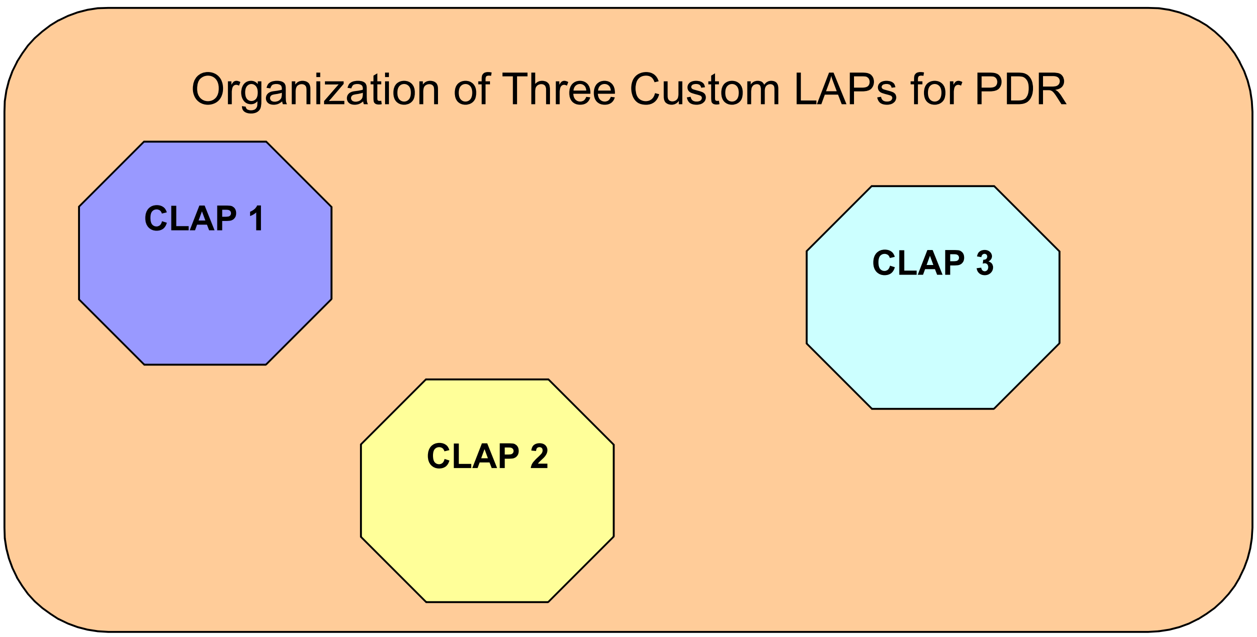


Diagram 1: Baseline Characteristics of a Network Environment

Diagram 1 shows a simple network environment composed of two local capacity areas. To meet reliability requirements and/or congestion constraints, DR resources are organized and deployed. To do so, CLAPs must be created.

3.4.1. Energy and Cash Flow Between Affected Parties

Diagram 2: Organization of Three PDRs at Custom LAPS (CLAPs)

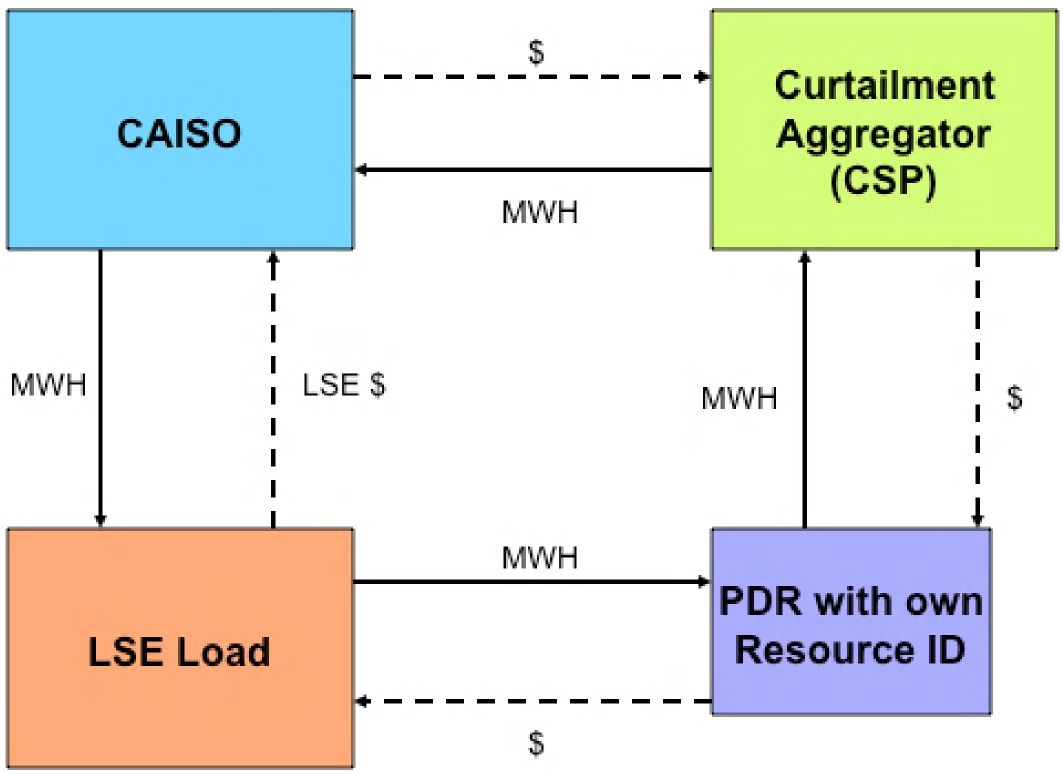


One or more CSPs proceed to organize PDRs at CLAPs to deliver DR resources to meet network reliability and/or congestion mitigation requirements. These CLAP based PDRs may be bid into ISO's Day-Ahead Market and or Real-Time Market.

- The ISO pays money to the responsible CSP(s) and receives in return Megawatt quantities from demand curtailments.
- The ISO delivers Megawatt quantities from demand curtailments as it would from other supply side resources.
- The PDR with its own specific Resource ID is the source of demand curtailment that the CSP harvests and bids into ISO's markets

Diagram 3 below visually depicts energy and money flows.

Diagram 3: Energy and Cash Flow Between Affected Parties



Retail Load is split at the bottom carving out the PDR with its own specific Resource ID. Since all financial settlement is between the ISO and the CSP there may be bilateral agreements outside of the ISO between the CSP, End-Use Customer, and LSE to ensure that compensation is appropriately shared.

3.4.2. Bidding PDR into ISO Markets at the CLAP

To illustrate bidding PDR into ISO Markets at the CLAP, Diagram 4 depicts the curtailment capability of a hypothetical LSE where the DR contributions are aligned with LSE customer accounts identified as the sources of the DR resource for a specific PDR with its own specific Resource ID.

In Diagram 4 below, there are three sources of curtailment capability – LSE A , which can deliver 10MW out of a 100MW load, LSE -B, which can deliver 10 MWs and LSE C which can deliver 30 MWs.

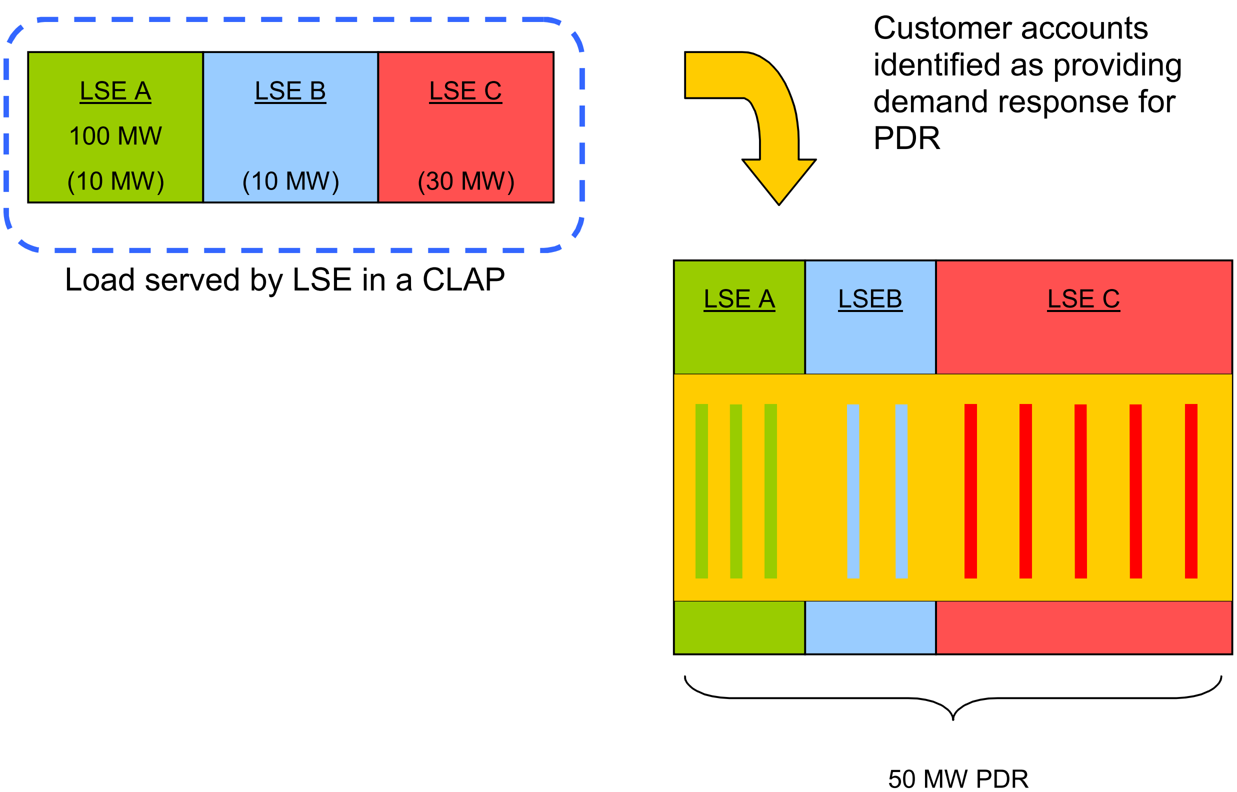
It is important to remember that under the PDR model, where DR resources are uncoupled from Load, it is possible for a PDR with its own specific Resource ID to come from more than one LSE service territory.

Assume for illustration purposes that Diagram 4 curtailment sources do cross over LSE boundaries. The reason for using this assumption will be explained in discussion of Diagram 7 below.

These three sources align with specific customer accounts. The visual depiction shows the curtailment source and the lines under each curtailment source are abstract symbols representing the actual customer accounts.

When these curtailment sources are combined, they create a 50 MW PDR that can be bid into ISO's markets.

Diagram 4: Sourcing Curtailment from LSE Customer



3.4.3. Single versus Multiple DR Programs and PDR

PDR can be bid into ISO's markets as a single DR program or as multiple DR programs. The distinction between single and multiple DR programs rests in how individual LSE customer curtailment capabilities are bundled and mapped into specific CLAPs.

Depending on the characteristics of the local area's network reliability/congestion constraint problems, one or more CLAPS may be organized and bid into ISO's markets.

Diagram 5 below depicts the bid curve for a single program PDR.

Diagram 5: Single DR Program PDR Resource Bid

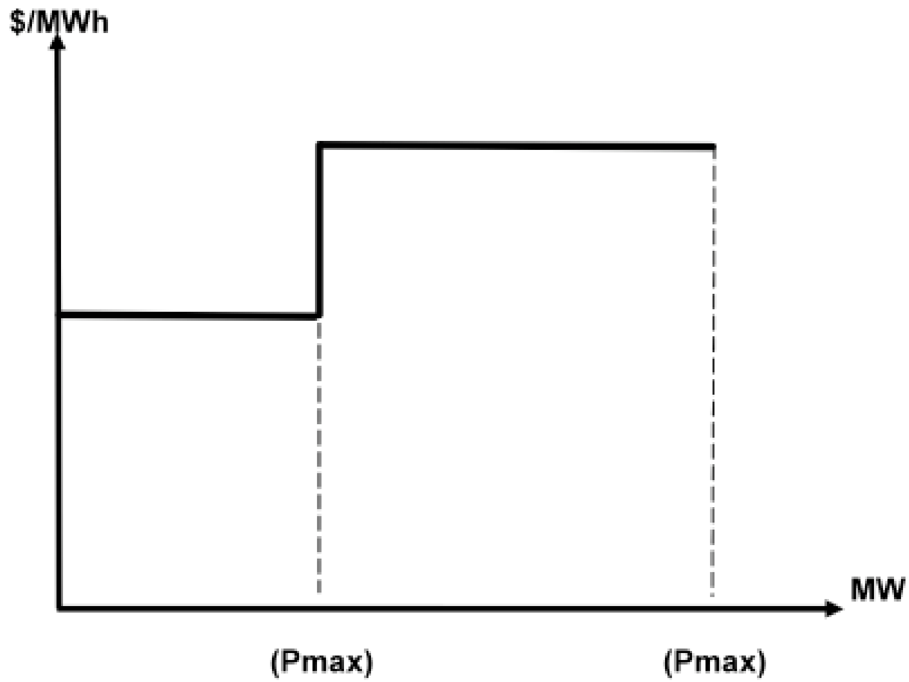
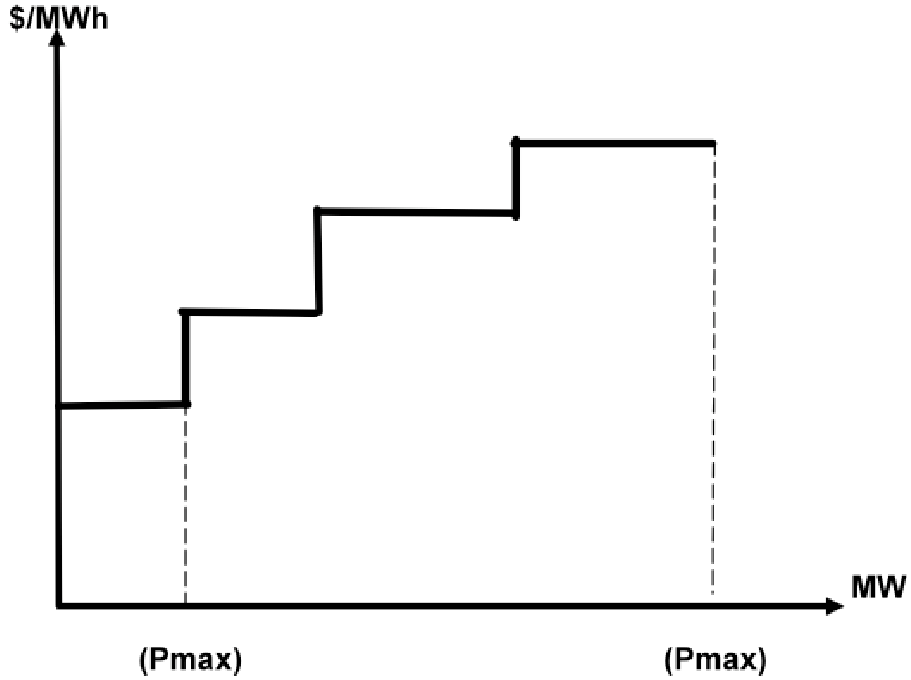


Diagram 6 below depicts the bid curve for a multiple programs case. The bid curve depicted in Diagram 6 represents the sum of multiple CLAPs that a CSP bids into the ISO's markets.

Diagram 6: Multiple DR Program PDR Resource Bid

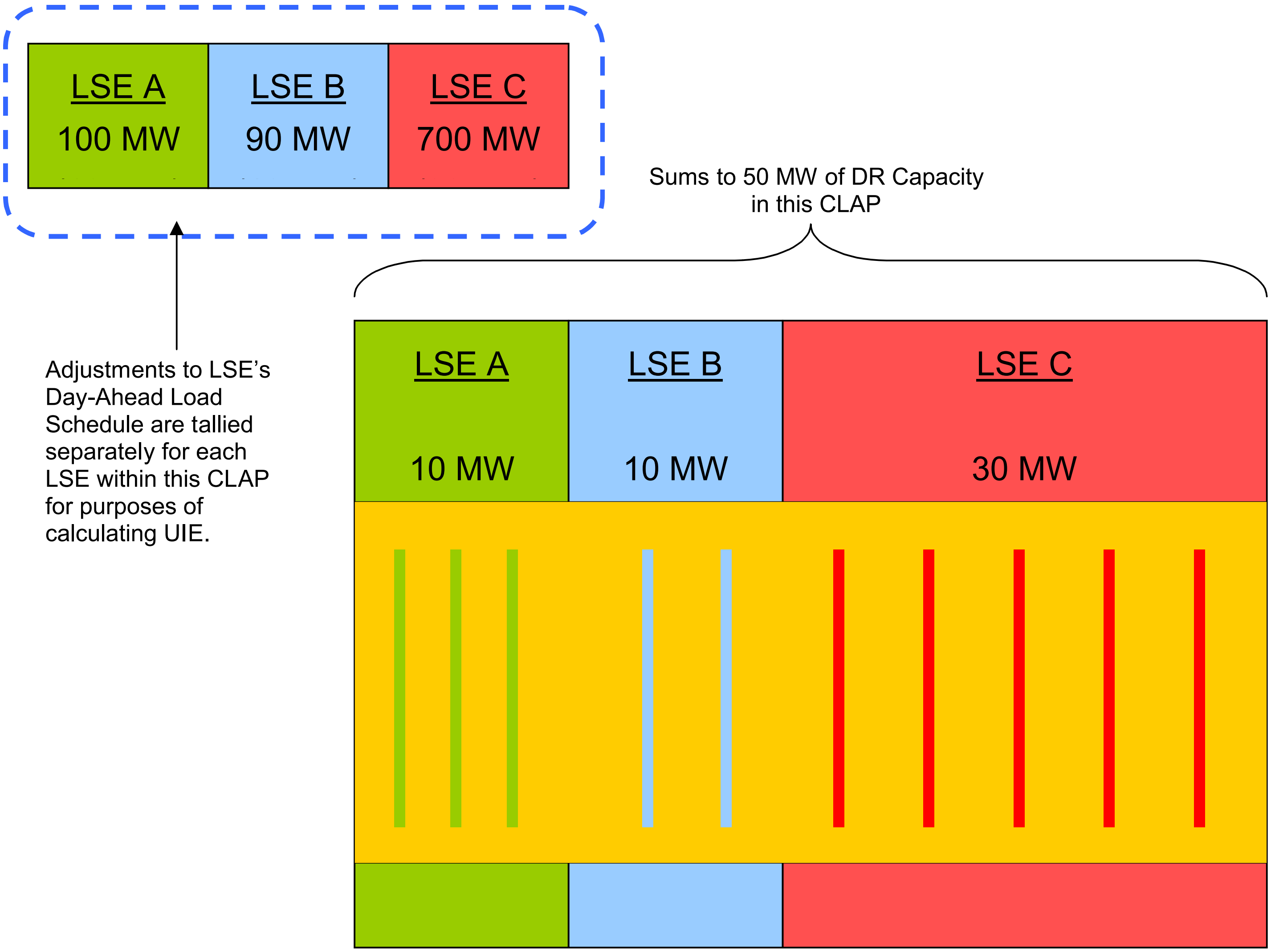


3.4.4. PDR Settlements

Returning to the curtailment sourcing case depicted in Diagram 4, consider the settlement of the PDR derived from the three curtailment sources – LSE-A, LSE B, and LSE C.

The PDR settlements flow from and to the CSP, to the right, for the energy and cash flows, as depicted in Diagram 3. Since, in the PDR Model the DR and the Load are unbundled, there is a Day-Ahead Schedule adjustment for the purpose of calculating Uninstructed Deviation (UIE) that is made separately for each LSE within the PDR, i.e. each LSE, LSE-A, LSE-B, and LSE C, will have an adjustment to their Day-Ahead schedule taking into account their Load's participation in the DR. This adjustment is necessary to accommodate curtailment sources that cross over LSE boundaries. This is visually depicted in Diagram 7 below.

Diagram 7: Depiction of PDR Settlement Involving Multiple LSEs



Now, with this foundation in place, consider a specific example of a Capacity Bidding Program (CBP) at the retail service level, which serves a PDR bid into ISO's wholesale markets.

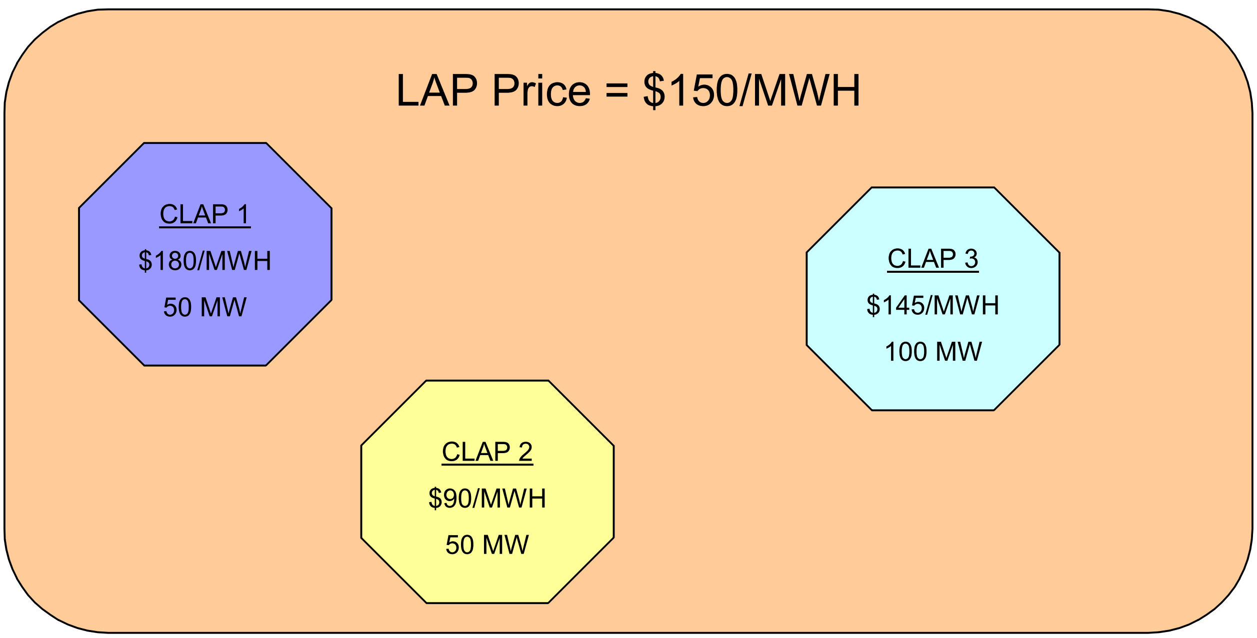
The CBP has the following characteristics:

- Monday-Friday (HE 12 – HE19)
- Three firm energy products: (1) 1-4 hour, (2) 2-6 hour, and (3) 4-8 hour
- 15,000 equivalent heat rate
- Maximum dispatch: 24 hours per month

The retail program is a 200 MW demand response program that translates into DR resources composed of a 50 MW PDR in one CLAP, labeled in Diagram 8 as CLAP 1; a 40 MW PDR in CLAP2, and 110 MW PDR (bid to curtail load) in CLAP3. In the Diagram 8 case, the PDR bid prices is set at $150/MWH (using a natural gas price of $10/MMBtu).

Diagram 8 below shows the locational marginal prices (PNode or CLAP prices) reflecting the market prices that settled in ISO's Day-Ahead Market. In other words, in Diagram 8, you see two numbers shown within each CLAP. The top CLAP number is a $/MWH value that reflects the CLAP market price, and the bottom number is the MW quantity making up the PDR, as described in the preceding paragraph.

Diagram 8: Value of Specific CLAPs when Called by SO and Cleared in ISO's Day-Ahead Market



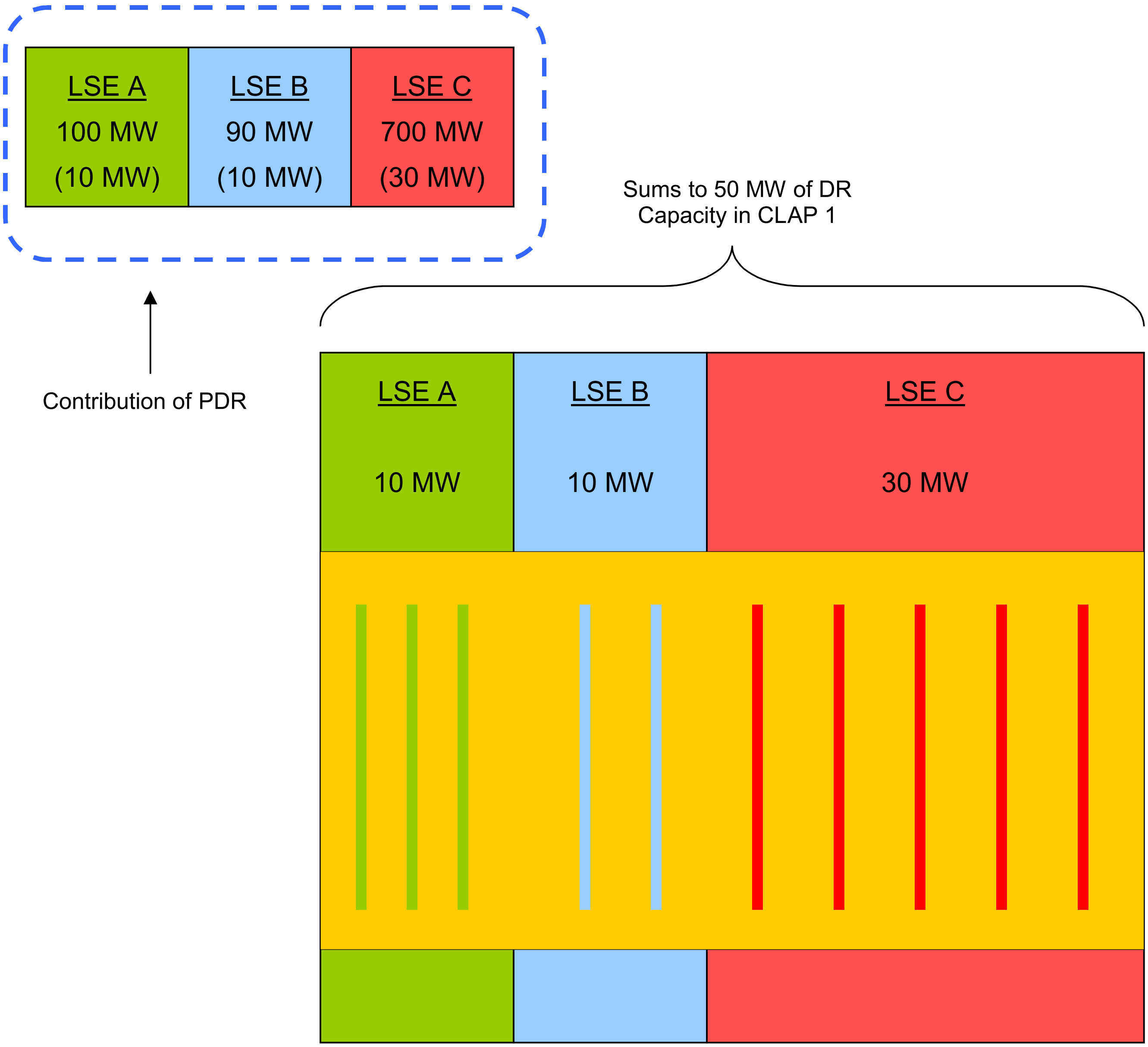
Continuing with the example case, consider the value differences shown between the CLAP market prices and the PDR bid prices at $150/MWH. In addition, this case also indicates that the DLAP market price is also $150/MWH.

- PDR in CLAP 1 – is the only PDR that is dispatched since the market clearing price exceeds the bid price by $30/MWH (180/MWH – 150/MWH = $30/MWH gain).
- PDR in CLAP 2 – is not dispatched since the market clearing price fails to meet the $150/MWH PDR bid price by $60/MWH.
- PDR in CLAP3 – is not dispatched since the market clearing price fails to meet the $150/MWH PDR bid price $5/MWH.

Given these outcomes, DR resources are developed in CLAP1 because the gain is superior to outcomes for CLAP2 and CLAP3. In principle, the higher priced CLAPs will draw DR resource development. The development of additional resources (DR or generic supply) in high priced CLAPs will lower market prices and cause convergence between CLAP and DLAP market prices.

Diagram 9 below visually depicts the settlement

Diagram 9: 50 MW Award for PDR in CLAP



Value derived from the settlement is allocated back to the CSP consistent with the performance of each specific PDR.   Table 2 below describes a settlement example where a bid to curtail submitted by a CSP involves the load of multiple LSEs. The example is based on Figure 9 above. The assumptions for this example are as follows:

- Three LSEs schedule 890 MW of Load in the Day-Ahead Market
- CSP clears 50 MW of load reduction in the Day-Ahead Market that is comprised of load from each of the three LSEs.
- Perfect compliance by PDR resource

Table 2 Settlement Example Involving Multiple LSEs in ISO Day-Ahead Market

	LSE A	LSE B	LSE C	Comment
LSE's DA Demand Schedule				
Cleared DA Schedule	100	90	700	
CSP's operation in DA Market				
Cleared Demand Reduction	10	10	30	
Settlement to CSP	-10	-10	-30	**Credit to CSP for DA DR award**.
CSP's operation in RT Market				
Cleared Demand Reduction	0	0	0	
Settlement to CSP	0	0	0	
LSE's Final Metered Demand				
Meter Read	90	80	670	
Settlement to LSE				
"Uninstructed" Deviation	See below			
Calculation of "Uninstructed" Deviation :				
LSE's Original DA Schedule	100	90	700	
"Actual PDR" (baseline - meter reads)	-10	-10	-30	**CSP informs ISO regarding allocation of MW between LSEs**.
LSE's Adjusted DA Schedule	90	80	670	
Actual Meter Read	90	80	670	
"Uninstructed" Deviation	0	0	0	

3.4.5. Applicable Price for Demand Response in PDR Model

The PDR proposal involves scheduling, dispatch and settlement of the curtailed load or PDR at the CLAP and the scheduling of the LSE base load at the Default LAP. LECG identified gaming concerns in the case when DR dispatches are not settled at the same location as the underlying demand schedules which are explained in “Comments on the California ISO MRTU LMP Market Design”, which is Attachment C to the ISO’s May 13, 2005 amendments to its MRTU comprehensive design as filed with FERC, which are available at

http://www.caiso.com/docs/2005/05/13/2005051314175518804.pdf).

The gaming opportunity for demand response that LECG identified (p. 62 in the LECG comments) is described as follows:

> “The sixth of the major implementation issues identified with the MRTU market design is the proposed mechanism for demand response. Since demand response buys power at the zonal/LAP price in the DAM and sells power back at the nodal price, demand response at nodes within constrained regions have a money machine whenever their actual load is less than their allowed maximum demand response offer. The LSE providing demand response would merely buy power equal to its demonstrated dispatch capability at the LAP price in the DAM and bid demand response at a low enough price to ensure it is dispatched nodally down to its planned consumption in RT, earning the difference between the nodal price and the zonal price for doing nothing. This would be equivalent to the effect of virtual demand purchases at zonal prices in the DAM that are settled at nodal pricing in real- time.
>
> “A load’s demonstrated dispatch capability is presumably limited by its maximum energy consumption but it may be economic to inflate this if the spread between the LAP and nodal price is material over a large number of hours. The implicit subsidy in buying at the LAP and selling at the nodal price could become expensive to other consumers. This cost could be exacerbated by some of the other market design features, such as the way LAP bids are cleared in the DAM, which would tend to magnify the difference between the DAM LAP price and the RT nodal price.
>
> “Conversely, demand response resources would have little incentive to reduce load at times when congestion is low but prices high. Indeed, demand response loads in unconstrained portions of the transmission system might rarely have an incentive to provide demand response, as the RT nodal price would need to rise above the LAP price before it would be profitable for them to respond. If there is material congestion within the LAP, the RT LAP price could be higher than the nodal price for these loads, diminishing their incentive to participate in such programs.”

The ISO believes that potential gaming opportunities with the PDR proposal can be mitigated by employing an adequate baseline methodology and, possibly establishing minimum bid prices and/or limited hours of operation for the PDR. In addition, the concern over gaming that LECG pointed out involves DR participation that occurs in a significant number of hours, but programs that aggregate numerous customers are more likely to involve infrequent operations. Aggregations of numerous customers may also be simpler to model in baseline calculations than a small number of individual customers. Further, the strategic modification of the baseline calculations, discussed in section 5.7. as an illustration of gaming, appears to be less likely when an aggregation involves numerous customers.

The ISO explored with market participants solutions to mitigate possible gaming concerns which include limited hours of operation (e.g., less than 200 hours per year) and establishment of predetermined bid prices that would not be expected to be exceeded in more than the limited number of hours. (If the limit on hours of operation were 200 hours per year, a minimum bid price to avoid the risk of gaming could potentially be the Default LAP price that was exceeded for only 200 hours in the previous year.) Alternatively, perhaps the baseline methodologies that the CPUC is developing provide adequate protection against gaming. The ISO will explore with the Market

Surveillance Committee during the March 12 meeting what conditions might be needed, if any, to allow the PDR model to support the goal of settling DR at the same location where it is dispatched.

The ISO notes that settlement of the energy for DR dispatches and the underlying demand schedules at different locations, with different LMPs, would require increased precision in the baseline calculation that is the basis for determining the amount of response, compared to direct settlement of DR as simply a capacity resource.

4. Proposed Timetable for Stakeholder Engagement

The ISO will seek board approval on the conceptual design of PDR in May 2009. A stakeholder process will continue after that time up to August 2009 to resolve and determine requirements for the seven key areas that are impacted by direct participation requirements as they relate to the design of PDR. The following table describes the ISOs proposed schedule for stakeholder engagement up to the May Board meeting.

<u>Plan For Stakeholder Engagement</u>

Tentative Date	Milestone
12/22/08	Publish Issue Paper
1/05/09	Stakeholder Conference Call
1/15/09	Stakeholder Meeting / Working Group Meeting
2/27/09	Stakeholder Conference Call
3/5/09	Publish ISO Straw Proposal
3/12/09	MSC/ Stakeholder Meeting
3/19/09	Stakeholder Comments following MSC/ Stakeholder Meeting
Late March	Stakeholder Conference Call
Week of 4/6/09	Publish ISO Draft Final Proposal
Week of 4/16/09	Stakeholder Conference Call
Week of 4/20/09	Stakeholder Comments following MSC/ Stakeholder Meeting
4/27/09	File Compliance Filing with FERC reporting on status of enabling the Direct Participation of DR resources in ISO Wholesale Markets
TBD	MSC Opinion Adopted
5/18-19/09	Presentation to ISO Board of Governors for Decision on Direct Participation of DR resources in ISO Wholesale Markets

4.1. Next Steps

The ISO, along with the stakeholder Demand Response working group, came to the consensus that the PDR proposal described in this document as compared to the other two options for PDR design was the most closely aligned with FERC Order 719 direction on direct participation. The addition of a required baseline methodology to measure performance of the PDR resource introduces complexity but also allows for measurable and reportable performance on Demand Response in ISOs wholesale energy markets. The dispatched PDR is also paid at the CLAP price rather than the DLAP price which the ISO believes will send the right price signals toward developing demand response where it is needed most i.e., in high priced areas.

The ISO, working with market participants through the next steps in the stakeholder process will address the direct participation issues that need to be resolved for implementation of PDR product..The seven areas that are impacted by direct participation that will be further addressed through the stakeholder process are described and discussed in section 5 of this document.

The ISO invites comments on whether this Straw Proposal has appropriately considered the pertinent issues and proposed reasonable and workable solutions. The ISO requests that stakeholders provide written comments by close of business on March 19, 2009 to the Direct Participation Mailbox, directparticipation@caiso.com. The ISO seeks comments of two general types: first, comments on the proposal for the design of PDR and second, comments regarding any of the specific DR design issues identified in this paper or on the upcoming MSC/Stakeholder meeting scheduled for March 12.

5. Impact of Direct Participation on Demand Response Products

To initiate the design of the Direct Participation functionality, the ISO published an Issue Paper on December 22, 2008, whose purpose is to identify the issues that the ISO recognizes and invite identification of additional issues that the ISO should address in its proposed market design enhancements to comply with Order 719. The Issue Paper was not intended to lay out specific modifications to the ISO's proposed market design enhancements, but rather to determine the scope of effort based on the identified issues, and if and how the issues impact the ISO's proposed market design enhancements. The ISO discussed the Issue Paper at a stakeholder conference call on January 5, 2009, and a stakeholder meeting on January 15. These materials, and stakeholder comments related to the Issue Paper, are available at

http://www.caiso.com/1893/1893e350393b0.html.

Based on comments received concerning the Issue Paper, the ISO has prepared this section of the Straw Proposal as its proposed resolution of the issues for implementing Direct Participation as part of the market enhancements for DR. This is not the final ISO proposal or recommendation, but rather is a means to focus discussion on workable resolutions of issues. This Straw Proposal will be discussed at a stakeholder and Market Surveillance Committee meeting on March 12, 2009, followed by another round of stakeholder comments that the ISO will consider as potential refinements to its proposal. The subsequent step in the ISO's stakeholder process is then the publication of a Draft Final Proposal, which is the ISO's statement of its anticipated recommendation to the ISO Board of Governors, subject to discussion at an additional stakeholder meeting and receipt of stakeholder comments. The proposed resolution of these issues will then be presented for approval as part of the overall market design enhancements for DR, first to the ISO Board of Governors, and then to the Federal Energy Regulatory Commission (FERC), through revised tariff language. At this point, the ISO anticipates that the proposed resolution must be considered to be a conceptual design, since there is a limited amount of time available for the compliance filing for Order 719. Resolution of issues as a conceptual design is not needed only for compliance with Order 719, but also because the ISO needs to begin detailed design steps with its software vendor given a goal of implementing enhancements to the MRTU Release 1 functionality about 12 months after MRTU Go-Live. This conceptual design will be sufficiently detailed to allow Board of Governors approval of the fundamental policies for the structure of the ISO markets, which will then be addressed in further working group processes and stakeholder meetings, and to inform FERC in the Order 719 compliance filing as to the direction being taken by the ISO.

Development of the conceptual design will be followed by additional discussion of implementation details related to the requirements of FERC Order 719 in stakeholder and working group meetings. The ISO has also announced plans for a comprehensive set of stakeholder meetings beginning in April, to develop details based on the ISO Board of Governors' policy guidance on conceptual design. Stakeholder meetings on this Straw Proposal and the subsequent Draft Final Proposal may reveal needs for additional meetings.

The ISO's implementation of the conceptual design will be described in its Business Practice Manuals and Participating Load Users Guide. This practice is similar to a number of other aspects of MRTU, in which the tariff establishes overall authorities and responsibilities of the ISO and market participants, and further details are established by the Business Practice Manuals. In parallel, the CPUC and other Local Regulatory Authorities will likely consider these issues and their application to their jurisdictional entities.

The next section, "Impact of Direct Participation on Demand Response Products "lays out each of the key issue areas the ISO determined are impacted by FERC Order 719. Generally, each topic begins with an overview discussion of the issues that the ISO identified in its Issue Paper and subsequent stakeholder discussions, followed by a summary of comments submitted by stakeholders that further describe the issues or that suggest alternative solutions, and finally by the ISO's initial proposed resolution of the issues. The stakeholder comments are summarized but the full comments are available on the ISO's web site at

http://www.caiso.com/1893/1893e350393b0.html.

5.1. Design Features and Issues to be Resolved

In order to employ the Direct Participation of DR resources in California's wholesale market, the ISO must address a range of related issues and assess their impacts on the ISO's systems, market design and business processes. Likewise, Market Participants will need to undertake a similar evaluation. The ISO identified the following seven categories as a framework to identify and resolve business issues and processes related to the Direct Participation directive in Order 719. The ISO shared this framework with stakeholders at the January 15 stakeholder meeting, and for consistency, organized this section of the proposal around these seven categories:

1. Qualification (program definition, participant and resource qualification)
2. Registration (resource characteristics, enrollment, transfers, testing & auditing)
3. Scheduling (system and resource forecasting, resource scheduling & bidding)
4. Notifications (market schedules & awards, RT dispatch, outages)
5. Metering and Telemetry (data availability, data exchange, data type & granularity)
6. Settlement (calculation of load changes, calculation of credits & charges)

7. Performance & Compliance Evaluation (resource, participant, program, and system performance evaluation, compliance monitoring)

These issues are individually examined in each subsection below. In each subsection, this document first describes the background for identifying and considering issues, then summarizes stakeholder comments received following the January 5, 2009 conference call and January 15, 2009 stakeholder meeting, and finally, presents a possible resolution of the issues for consideration and further discussion in working group meetings. As discussed previously, the Straw Proposal is not a final ISO proposal but a discussion piece for the ISO and its stakeholders to work toward the conceptual design that will be presented to the ISO Board of Governors. In summarizing stakeholder comments, it has been necessary to identify the key points to maintain brevity, and to present the comments of diverse parties in a consistent format, but the intent is not to alter the substance of any comments that have been submitted. The full text of the stakeholder comments can be found at http://www.caiso.com/1893/1893e350393b0.html.

5.2. Qualification

5.2.1. Background

A fundamental issue is who is eligible to directly participate in the ISO markets on behalf of DR resources. FERC has identified a new market participant that it refers to as an “Aggregator of Retail Customers”, but because direct access retail end-use customers are aggregated for purposes of scheduling energy usage by Electric Service Providers, the ISO finds that a parallel term, “Curtailment Service Provider” (CSP), which is used in some other organized markets, clarifies what is being aggregated. The term CSP highlights some of its roles and responsibilities, i.e., that this entity bids DR into the ISO’s markets on behalf of end-use customers, separately from the LSE’s scheduling of the energy that the end-use customers consume.

Remaining issues involve the eligibility of DR resources to participate in ISO markets, and these have been addressed in stakeholder comments.

5.2.2. Stakeholder Comments

EnerNOC identifies several types of entities and programs who could potentially be eligible to directly participate in DR programs, including Load Serving Entities (LSEs), Utility Distribution Companies (UDCs), Electric Service Providers (ESPs), Curtailment Service Providers (CSPs), end-use customers, distributed generators, and permanent load shift and energy efficiency resources. EnerNOC suggests that the registration for a CSP might not require becoming or interfacing with a Scheduling Coordinator. EnerNOC suggests that the minimum resource size might be 0.1 MW, and that eligible programs include DA, RT, and price-responsive. Issues include whether customers can participate in more than one program, which programs will be eligible to participate in which ISO markets (energy, capacity, ancillary services), and which programs provide an RA credit. DR resources can have differing availability requirements, with variation in being summer only or annual programs, hours per year of availability, number of events, hours per event, different event-initiation triggers, price, demand levels, operating reserve levels and/or emergency protocols. EnerNOC asks, as an issue, how the administrative costs associated with DR programs are administered.

North America Power Partners LLC (NAPP) states that all California customers located within the ISO managed region should be allowed to participate as DR resources in the ISO markets, whether they are IOU or non-IOU customers, including participation by aggregated loads as small as 100 kW in all ISO markets (DA and RT energy and ancillary services), which would be managed as a "portfolio" for purposes of assessing performance. NAPP disagrees with the tentative conclusion of the ISO Issue Paper that a DR resource may only be registered to one CSP, noting that different CSPs may focus on different markets (e.g., one CSP for Ancillary Services and another CSP for other markets), and that a limitation to one CSP per DR resource may not lead to the most efficient use of DR resources. NAPP suggests that the ISO should allow DR aggregations that CSPs are operating within the utilities' DR programs to be bid by CSPs for delivery periods that are outside of IOU contract delivery periods. NAPP also suggests that if customers who participate in DR programs maintain back-up generators or on site "behind-the-meter" generation, these generators might be able to participate in some of the ISO markets.

Southern California Edison (SCE) agrees with using the term "Curtailment Service Provider" to represent an aggregator of retail customers as the new market participant. SCE suggests that CPUC tariff allowances for dual participation in DR programs should be explicitly addressed. For example, if the LSE's interruptible tariff allows a customer to also participate in other DR programs, it needs to be determined whether a resource is eligible to be registered with more than one CSP or LSE at a time, and whether dual participation in multiple programs (rather than specific DR events) will be accommodated. SCE states that while defining the roles of LSEs and CSPs, the ISO needs to make liability assignments between counter parties very clear, through details in the Business Practice Manuals.

5.2.3. Discussion

The comments by EnerNOC and NAPP address a broad range of issues. Addressing the requirements for enabling a new type of entity to participate in the ISO markets, within the short timeframe before the Order 719 compliance filing, requires limiting the issues that are resolved through this stakeholder process to only those that are required. As noted in section 1, the ISO markets have included PL functionality since the ISO started operations in 1998, and this continues in MRTU Release 1. To the extent that mechanisms already exist to support PL, this Straw Proposal does not seek to reinvent them. Also, the ISO is a market operator that interacts with business entities that represent suppliers and end-use customers, and is not an operator of (a) specific DR programs that directly enroll end-use retail customers, or (b) operate other market resources that would compete with market participants' resources.

All market participants that buy or sell in the ISO markets either provide or purchase products that involve financial obligations, and it should not be surprising that market participants must formally agree to these obligations. The means of agreeing to these obligations is to become a Scheduling Coordinator, and therefore all market participants must either be or be represented by a Scheduling Coordinator. Executing the agreements to be a Scheduling Coordinator is not onerous or restrictive, and the agreements simply obligate the market participant to understand and agree to the provisions of the ISO tariff. Additional obligations such as metering depend on the types of resources that the Scheduling Coordinator offers in the market. Although the ISO assists all market participants in bringing their resources into the ISO markets, the ISO does not fund the administrative costs of any market participant.

In the context of DR, the ISO's role is to implement market structures that allow market participants' DR programs to participate in the ISO's markets on a comparable basis as other resources. The ISO's markets are founded on bidding in DA and RT market timeframes, using hourly or sub-hourly time intervals, and recognize resources' operational constraints as well as grid operational constraints.[11] Thus, the ISO's market operations provide the mechanisms for market participants to

[11] Resources that are not scheduled on hourly or sub-hourly time intervals, such as permanent load shifting or energy efficiency, have roles in LSEs' overall resource planning but are not participants in ISO markets.

describe their resources' operational constraints as part of their bid submission using DDR and PDR, but the ISO does not determine the resources' operational constraints. For example, the ISO's DDR and PDR designs already allow PL aggregations to be as small as 0.1 MW, but do not create the aggregations, since that is the CSP's role. The utilities' retail programs include reliability-based/emergency response programs such as interruptible tariffs, but the ISO's markets do not have emergency response products. Instead, the ISO is aware of the utilities' reliability-based/emergency response programs, and coordinates with the utilities when those programs are needed to maintain system reliability. The ISO tariff already limits the participation of the same end-use customers in emergency response programs and PL resources, and the ISO does not see the addition of CSPs to the market as changing the existing tariff provisions. The ISO does not currently operate a market for resource adequacy capacity, and instead, works with Local Regulatory Authorities (LRA, such as the CPUC) to develop RA requirements that market participants must meet, with the LRAs defining which and how resources qualify as RA capacity.

For these reasons, the ISO does not find it necessary to either broaden its role beyond that of market operator, or to relax the requirements for representation by Scheduling Coordinators. Conversely, no comments have suggested that the requirements for representation by Scheduling Coordinators, as currently defined, are not sufficient to cover the new roles of CSPs. Thus, the ISO concludes that CSPs must be or be represented by a Scheduling Coordinator, but does not see need for extensive revisions to the tariff provisions governing Scheduling Coordinators.

The current Scheduling Coordination Certification requirements may be found at the ISO website at:

http://www.caiso.com/docs/2005/10/05/2005100520241822328.html

One necessary requirement is that when seeking to qualify a DR resource, the CSP must certify to the ISO that participation by its resource is not precluded by the Local Regulatory Authority, e.g., the CPUC. In other ways, the eligibility of the DR resources themselves does not seem to be affected by whether they are operated by a CSP that is the same entity as the LSE, or by an independent CSP, through Direct Participation.

A final issue for this section is whether multiple CSPs can represent the same end-use customer. At this point, the ISO contemplates allowing only a single CSP to represent an end-use customer, although this provision may be reconsidered after the market has experience with Direct Participation.[12]

5.2.4. Other Issues: Credit Requirements

The ISO establishes credit requirements for participation in ISO markets in order to ensure that each market participant adequately secures its financial transactions with the ISO. Credit requirements apply to Scheduling Coordinators who represent Supply resources, including PLs. Any financial penalties triggered during the delivery period would accrue through the ISO settlement system to the relevant SC. Based on the provisions of this Straw Proposal, and review of the existing credit requirements for Supply resources, the ISO has concluded that the exposure of CSPs is within what has already been established for Supply resources.[13] Thus, the ISO's preliminary

12 Future reviews of the results of actually implementing Direct Participation may conclude that this requirement can be relaxed.

13 SCE's comments suggest that the credit requirements for CSPs should be the same as for LSEs and Community Choice Aggregators. However, CSPs do not take on the primary role of providing energy, and instead are included in the ISO tariff's definition of supply resources.

analysis is that the CSP should simply be subject to the same, existing credit requirements as other Supply resources.[14]

In the event that financial penalties are adopted to protect against non-performance or under-performance by CSPs, the ISO should have assurance that it will receive payment. Each CSP's liability would need to be evaluated and a credit requirement developed, if financial penalties are adopted.

5.3. Registration

5.3.1. Background

The Issue Paper identified three distinct registration functions that need to be addressed:

- New DR resource wishing to register with a CSP / LSE,
- Existing DR resource registered with a CSP / LSE who wishes to change to a different CSP / LSE, and
- Existing DR resource registered with a CSP / LSE that wishes to withdraw from the DR market.

Within these three scenarios, to make the DR resource market effective, the Issue Paper suggested needs for a series of controls / checks and balances to ensure appropriate scheduling of DR resources. The ISO will establish necessary overall rules in its tariff to ensure the integrity of registering and scheduling DR resources, and further detail the supporting processes in its Business Practice Manuals and Participating Load Users Guide through a working group and stakeholder that will follow the Order 719 compliance filing. The Issue Paper suggested that the appropriate provisions for DR resources appear to be that:

- A DR resource can only be registered to one CSP / LSE at a time
- The DR resource is registered to the correct CSP / LSE
- All registered DR resources are aware that they are registered with a specific CSP / LSE
- Confirmation of any change of CSP / LSE is communicated to the DR resource, and the DR Resource affirmatively confirms that change
- A DR resource who wishes to leave the DR resource pool confirms that it has been removed
- The CSP / LSE's report to the ISO of DR capability is accurate and reflects the registered DR resource capacities.
- Load schedules and DR bids are submitted using consistent load aggregations by the LSE and CSP, to the extent that a DR program requires such consistency.

A variety of implementation details will need to be resolved through the working group and stakeholder process following the ISO's Order 719 compliance filing. Customer migration will need

14 At the January 15 stakeholder meeting, the ISO identified a potential issue as to whether CSPs' bidding of increases in energy consumption needs to be limited or adds other requirements. The ISO offered examples that a CSP that manages an end-use customer's thermal energy storage system would bid to buy economical energy in off-peak hours in order to reduce demand during peak hours, and may result in a net increase in MWh over the course of a day, but that this seems to be a legitimate role for a CSP. However, a CSP taking over a significant fraction of an end-use customer's energy procurement may be beyond the appropriate role of a CSP that is not also the customer's LSE. Stakeholders have not submitted written comments on these issues, and the issues do not seem to clearly define new requirements at this time, either as credit requirements or restrictions on bidding by the CSP.

to be tracked as end-use customers enroll in and discontinue their participation in DR programs, and move between LSEs (including direct access Electric Service Providers), particularly if the end-use customers' migration between CSPs and LSEs do not occur at the same time. Registration of a PL resource needs to ensure that the end-use customers that comprise the resource are located within the designated areas. The ISO's DR programs require the aggregation of end-use customers within local areas (Custom Load Aggregation Points (Custom LAPs) within Local Capacity Areas for DDR, and tracking within Sub-LAPs for PDR). Customer migration will require updating of the aggregation data that underlie the submission of Schedules and Bids by LSEs and CSPs, as well as the operational characteristics of DR resources (available capacity, loss factors, etc.), to ensure that correct prices are applied in settlements. If customer migration results in changes to the products (e.g., Ancillary Services) that are bid into ISO markets, Schedule 1 of the Participating Load Agreement will require updating, and updates to the PL's implementation plan will track other resource attributes such as available capacity.

In some ISO markets, the ISO has the responsibility of managing the registration / confirmation process. How this will be managed within the scope of the DR program under MRTU is among the questions addressed below, and will be among the topics of ongoing discussions. Two of the alternatives are: (1) the ISO could actively manage the registration and confirmation process, by constructing and maintaining large databases of end-use customer registrations and assignments to CSPs and LSEs, or (2) market participants could be responsible for managing end-use customer registrations, pursuant to rules and processes that the ISO and CPUC would establish. Discussion during the current stakeholder process, and the working group and stakeholder process that will follow the Order 719 compliance filing may identify additional options that are between these two fundamental options, or that are hybrids of them.

5.3.2. Stakeholder Comments

EnerNOC suggests that the ISO will need to register resources (customer locations) with a specific resource ID. The aggregator would submit the list of resources that are behind the load reduction bid that will respond when DR events are initiated. EnerNOC identifies issues as being how resources are identified with a CSP, and how new customers are registered in the program.

NAPP proposes that the ISO should maintain central databases that support the registration and settlements of market resources and transactions, which would allow the EDC(?), LSE, CSP and ISO to enter, review and approve each DR resource registration, transaction and settlement. Metering would be maintained outside of the ISO system and reported to the ISO by the corresponding DR resource aggregator or provider.

SCE identifies communications among the various market participants as an important issue requiring a set of standards/protocols, with respect to specific customer account program enrollments, changes as customers move in and out of programs, and event participation. AReM also identifies "customer migration" as an issue with Direct Participation that needs further discussion.

PG&E suggests that the ISO should require the CSP to notify the LSE soon after enrollment when a customer of the LSE is enrolled in the CSP's DR program, before bids by the CSP are scheduled or dispatched, and require the CSP to notify the LSE when the CSP's DR resource is scheduled or dispatched for an LSE's customer.

As one aspect of the ISO's response as market participants' needs are identified, the ISO suggested an option in the DDR model to allow PLs to represent only a fraction of the end-use customers' total metered demand if some of their demand is not price-responsive, instead of the requirement in

MRTU Release 1 that the CLAP must represent 100% of their metered demand (i.e., "partial participation"). AReM views the ISO's proposal to allow "partial participation" in its DDR programs as going in the right direction, and would like further discussion including any need to set a "maximum participation limit … to avoid gaming in settlements" and the rules regarding an SC "separating the metered demand between the PL and its Default LAP."[15]

The California Department of Water Resources – State Water Project (CDWR-SWP) is concerned that the ISO's "partial participation" proposal in the DDR model could result in limited PL at locations with high LMPs, while loads at locations with low LMPs may designate 100% of their demand as PL.

5.3.3. Discussion

After discussion at the January 15 stakeholder meeting and review of stakeholder comments, the ISO continues to see the principles outlined above in section 5.2.1, "Background", to be appropriate as requirements for Direct Participation. As noted in section 5.2.1, the ISO will establish the overall rules in its tariff that are necessary to ensure the integrity of registering and scheduling DR resources. Details of the supporting processes will be described in the ISO's Business Practice Manuals and Participating Load Users Guide, to be developed through a working group and stakeholder process that will follow the Order 719 compliance filing. There is no doubt that developing details of these processes will require time for open discussion, and first establishing the fundamental requirements will then help to focus the subsequent discussion of the details that are required for implementation.

As documented in the MRTU Release 1 Participating Load User Guide, the Participating Load Agreement (PLA) establishes the roles and responsibilities for being a PL in the ISO markets, and Schedule 1 of the PLA describes its participating resources in general terms. The Participating Load Implementation Plan and Resource Data Template are less formal documents that certify resource capabilities. Once resource characteristics are established through these documents, market bids describe the day to day (and hour to hour) availability of resources. These documents provide a flexible structure for managing DR resources, and provide the ISO with the information it needs to manage its markets without excessive needs for the ISO to track individual end-use customers. Tracking the individual customers that make up PL resources is the responsibility of the CSP that bids the resource.[16]

The ISO recognizes that LSEs as well as CSPs need to be aware of DR enrollments and schedule changes. LSEs will base their load schedules on the actual usage of the customers who they serve, and lack of knowledge about DR schedule changes affecting their customers could cause error in their forecasts. Thus, the ISO agrees with SCE and PG&E that LSEs should be informed of DR enrollments and schedule changes. The ISO's tariff will need to establish the principles for this data

---

15 When the ISO presented the "partial participation" option as part of the DDR design, in the December 12, 2008, demand response working group meeting (presentation available at http://www.caiso.com/209b/209b87036bc80.pdf), the ISO identified a potential opportunity for "gaming" if a Participating Load strategically selects the fraction of its demand that is settled at its CLAP price vs. its Default LAP price. The ISO recognizes this as an issue for future consideration, among a number of detailed design issues.

16 In determining whether additional data are needed to track individual customers, an analogous situation could be the tracking of load migration between LSEs so that Congestion Revenue Rights (CRRs) can be reassigned to the LSEs that serve end-use customers in each month. Because the ISO allocates CRRs to LSEs to manage congestion costs that the LSEs incur in serving their customers, the ISO needs to maintain as much precision as possible in its allocation of CRRs. Nevertheless, the information that the ISO tracks for the reallocation of CRRs from month to month is limited, consisting of data such as account number, customer class, and approximate usage for individual customers over one MW in size. That is, extensive databases about end-use customers have not been required. In contrast, each CSP is responsible for managing its DR resources and will see the financial impacts of any mismanagement in its final settlements. While the LSE can receive CRRs for serving load, CSPs are not awarded CRRs for managing DR. The number of individual customers who participate in DR programs could be quite large for programs that serve small customers. Therefore, there appears to be no need for the ISO to develop complex systems for tracking individual end-use customers to actively manage the registration and confirmation process. Instead, market participants should be responsible for managing end-use customer registrations, pursuant to rules and processes that the ISO and CPUC will establish.

exchange, followed by development of implementation details in the Business Practice Manuals and Participating Load Users Guide. In actual

5.4. Scheduling

5.4.1. Background

Once a CSP becomes certified for participation in ISO markets and registers its resources, actual participation proceeds with the submission of bids for energy and/or capacity products (e.g., Ancillary Services). The CSP's preparation of markets bids involves collection of aggregated data for its end-use customers, and forecasting the availability of price responsive resources for the operating day, as well as business decisions such as determining its bid price. The format of bids for submission to the ISO market in MRTU Release 1 is documented in the MRTU Release 1 User Guide, and consists of bids for two separate resources: scheduling of load as a demand resource, and separate bidding of DR as a supply resource (similar to a generator). This is expected to have only limited change in structure for the DDR and PDR models.

5.4.2. Stakeholder Comments

NAPP suggests that DR resources should be allowed to participate using Firm Service Level (making a minimum threshold usage commitment) or Guaranteed Load Drop (committing that they will shed a specific amount of load at the time of the call event). EnerNOC states that an issue to be addressed is how DR is offered into the ISO markets.

5.4.3. Discussion

As the ISO discussed in the January 15, 2009, stakeholder meeting, the scheduling functions summarized in section 5.3.1 do not appear to be changed by the addition of the CSP as a market participant that is separate from the LSE. As a general rule, when the LSE and CSP are separate entities, scheduling functions that would be performed to schedule demand that if it were not participating in DR would remain with the LSE, but functions that exist because of participation in a DR program would be the CSP's responsibility. At a DR working group meeting on December 12, 2008, a representative of SCE suggested that the respective roles of the CSP and LSE should be as follows:[17]

Who develops pilot program and applies to PUC for approval?	CSP [18]
Who markets program and enrolls customers?	CSP
Who pays customers capacity payment to participate?	CSP
Who procures, installs, reads and maintains metering, telemetry and auto DR equipment at customer sites?	CSP
Who registers participant load with ISO as a new Resource ID?	CSP
Who coordinates PDR acceptance and certification test?	CSP
Who forecasts hourly energy usage for each Resource ID?	N/A [19]

17 The table in SCE's presentation at the working group meeting also included proposals concerning program funding and financial settlements between the LSE and CSP, which are separate topics from roles in the scheduling process and thus are not included in the table as shown here.

18 By including this row, the ISO is not making any determination whether independent CSPs must apply to the CPUC for program approval.

19 The ISO's understanding is that this proposal at the working group meeting includes each LSE and CSP preparing its own load forecast.

Who submits energy bid for Resource ID in DA market?	CSP
Who forecasts available load reduction capacity that can be bid in RT?	CSP
Who models actual load response (if necessary) when ISO dispatches PDR in RT market?	CSP
Model output assumed to be integrated with meter data and communicated with ISO.	CSP
Who submits RTEM bids?	CSP
How are Imbalance Energy bid levels decided?	M&V vs Baseline [20]
Who receives ADS dispatch for Imbalance Energy?	CSP
Who activates load reduction via auto DR?	CSP
Who measures and verifies load reduction?	CSP (recommend that LSE, ISO verify also) [21]

While the details of these roles are subject to discussion during the stakeholder meeting on this Straw Proposal, the ISO considers this table to be a useful illustration of the ISO's Straw Proposal. The ISO notes that the LSE needs to have metering compliant with CPUC standards for all of its retail end-use customers, and that the assignment of the metering and telemetry role discussed in this table concerns any additional needs for PLs, which are discussed in section 5.5 of this Straw Proposal.

Among the key issues to be addressed at this point of completing the ISO's proposal is who is responsible for measuring and verifying load reductions. The ISO anticipates that all entities that are affected by PL resources (including the ISO, CSP, and LSE) will actively monitor load reductions, and the question is whose calculations form the basis of financial settlements. At this time, the ISO believes that settlements will be the most transparent to market participants, and that settlements will function the most smoothly if the ISO takes on this responsibility. However, the ISO invites comments on this issue.

Some retail DR programs include performance characteristics such as Firm Service Level and Guaranteed Load Drop, which are referred to in NAPP's comments. Except for RT response to the dispatch of energy from ancillary service and RUC capacity, these concepts do not apply in the ISO's markets. For ancillary services and RUC, the ISO must know that it has a specific amount of capacity available that will be available when needed in RT operations. Other sources of ancillary services (i.e., generation and imports) provide this operational certainty of having a specific amount of capacity available when needed, and RUC resources similarly offer specific capacity to RTM. To be comparable to the other sources of ancillary services and RUC capacity, so that capacity can be awarded using the same market mechanisms, PLs must also provide a specific amount of capacity. CSPs may include Firm Service Level and Guaranteed Load Drop commitments in contractual arrangements with their end-use customers, and if honoring these commitments results in deviations from schedules issued by the ISO, the difference will be settled as RT imbalance energy – the same as other sources of RT imbalances.

20 The ISO's understanding is that this proposal at the working group meeting places responsibility for both measurement and verification, and baseline, calculations on the CSP.

21 This table entry reflects SCE's suggestion. See the text of this section for the ISO's assessment of who should measure and verify load reductions.

5.5. Notifications

5.5.1. Background

After Scheduling Coordinators submit their bids into the ISO's RT markets, the ISO runs its market software to determine final schedules. At the completion of DAM, the ISO publishes DA prices as public market information, and publishes schedules separately to each Scheduling Coordinator. While running RTM, the ISO uses the Automated Dispatch System (ADS) to communicate resource-specific dispatches, and publishes RT prices as public market information. In the Issue Paper, the ISO indicated that it sees little if any change in mechanisms for communicating schedules and dispatch due to adding Direct Participation to the DDR and PDR designs. The ISO identified issues and invited stakeholder comments regarding whether the LSE needs a copy of schedule changes and dispatches resulting from CSP's bids, to be sent by the ISO, and whether the CSP needs a copy of the LSE's scheduled energy, to be sent by the ISO.

The ISO has previously indicated that it sees no need to track outages for DR, other than unavailability of awarded AS capacity. The Issue Paper suggested that there is no apparent need to change this conclusion due to Direct Participation.

5.5.2. Stakeholder Comments

PG&E suggests that the ISO should require the CSP to notify the LSE when the CSP's DR resource is scheduled or dispatched for an LSE's customer, as well as to require the CSP to notify the LSE when the CSP enrolls a customer of the LSE is enrolled in the CSP's DR program.

EnerNOC identifies issues of how events are triggered, what minimum types of communication equipment the CSP and its customers will have to install in order for communications from the ISO to be received to alert of DR events, how the event notification is transmitted to the CSP and/or customers of the CSP, and what response time is required after notification is received.

5.5.3. Discussion

As noted in section 3.2.3, the ISO recognizes that LSEs as well as CSPs need to be aware of DR enrollments and schedule changes. LSEs will base their load schedules on the actual usage of the customers who they serve, and lack of knowledge about DR schedule changes affecting their customers could cause error in their forecasts. Thus, the ISO agrees that LSEs should be informed of DR enrollments and schedule changes. Similarly, the CSP needs to be aware of the amount of demand that is being scheduled by the LSE, when the CSP is using the DDR model, since AS awards will be subject to no-pay provisions if AS awards exceed the scheduled demand for the CLAP. Knowledge that the LSE had not scheduled sufficient demand to support the AS award to the CSP would allow the CSP to enter outage data informing the ISO that the AS capacity is unavailable.

Exchanging data about MW quantities does not need to include data about bid prices, or quantities that were included in bids but not scheduled or dispatched by the ISO, which a market participant may consider confidential. The ISO's tariff will need to establish the principles for this data exchange, followed by development of implementation details in the Business Practice Manuals and Participating Load Users Guide.

Regarding the mechanics of schedule and dispatch notifications, the ISO has existing mechanisms for communicating schedules in the DA market, and dispatches in the RT market. These mechanisms and their timing requirements are documented in the User Guide. Other than to communicate MW quantities of demand schedules and dispatches to both the CSP and LSE, the

ISO has identified no need to change the existing notification mechanisms, and plans to continue to use the existing mechanisms.

5.6. Metering and Telemetry

5.6.1. Background

The Issue Paper addressed two types of issues: existing tariff impediments that will require clarification, and metering requirements for DR participation in the ISO markets.

One issue for tariff clarification is the provision in MRTU Tariff section 4.5.1.1.3 that only one Scheduling Coordinator may register at any point in time to represent the same meter point for a ISO Metered Entity. This tariff provision is discussed in detail in the Issue Paper, and that discussion does not require repeating here. The discussion's fundamental conclusion is that the ISO tariff does not fundamentally prohibit the situation where one SC schedules demand while another SC submits demand curtailment bids, particularly when the end-use customer is a SC Metered Entity. The issue of how the CSP may participate in ISO markets is the general topic of this Straw Proposal, and section 4.5.1.1.3 can ultimately be clarified to reflect the final policy resolution. However, the MRTU Tariff does not currently have provisions to address dual bids by the CSP and LSE, and in particular does not address how to allocate the value of a dispatched Demand curtailment between two Scheduling Coordinators representing the CSP and the LSE (and the underlying interests that they represent), and a substantive policy decision needs to be formulated about how any allocation should be made. The financial settlements issue of how to allocate revenues between the CSP and LSE is addressed in section 3.6 of this Straw Proposal.

The other issue identified in the Issue Paper for tariff clarification involves the definition of ISO Metered Entity, which states that a ISO Metered Entity is one of several types of entities, one of which is "a Participating Load". The ISO will clarify the tariff definitions to reflect that a PL is not necessarily a ISO Metered Entity. On these two tariff issues, the Issue Paper has established a sufficient background to develop the needed tariff clarifications.

An additional clarification that will be needed is that the current tariff does not define when a PL must be a ISO Metered Entity or a SC Metered Entity. Stakeholder comments were invited on this issue, but none have been received to date. As a Straw Proposal for further discussion, the ISO proposes that a PL that connects to the ISO Controlled Grid without other loads being served from the same grid takeout point must be a ISO Metered Entity, and otherwise PLs would be SC Metered Entities.

Substantive issues that need to be addressed further involve the specification of meter data for DR, and the responsibilities for meeting these requirements, when there are separate LSEs and CSPs. The current Metering Protocol and Tariff requirements may be found at the ISO website at:

http://www.caiso.com/docs/2005/10/01/2005100116065757 62.html

PLs and their Scheduling Coordinators must provide revenue quality metering data to the ISO. PLs and their SCs must ensure that revenue Meter Data is made available to the ISO in accordance with the ISO tariff and Metering Protocol. The specific requirements for ISO Metered Entities (if applicable) and details regarding the ISO certified meter, including the ISO's standards for the certification of a "Load-only" meter, can be found in the metering section on the ISO Home Page at http://www.caiso.com/docs/2005/10/01/2005100114481329995.html.

For all Loads of PLs, Sections 2.2.3 and 2.3.4 of the Metering Protocol of the ISO tariff require that revenue meter data must be recorded and submitted at 5-minute intervals for purposes of financial settlements. Pursuant to that requirement, ordinarily all Loads participating in ISO markets, including

AS and RT Imbalance Energy markets, must have revenue quality metering equipment that records data at intervals no longer than five minutes. For the MRTU Release 1 and thereafter, the 5 minute interval reading may be constructed by dividing a 15-minute interval reading into three equal values.

Among the issues to be considered is whether the same meter is applicable for settlement and validating compliance of services provided by the LSE (i.e., Energy) and the CSP (e.g., Ancillary Services). As discussed in the User Guide that is being developed for PL resources in MRTU Release 1, a separate set of measurements is already required as telemetry for PLs that provide Ancillary Services, while Settlement Quality Meter Data are used for Energy settlement. Whether there are needs for the LSE and CSP to maintain separate metering (rather than both entities using a common meter), whether it would be technically feasible for telemetered meters to be registered to the Scheduling Coordinator for the DR Participant, whether the data from such meters could be used for some settlement purposes, and the technical and financial feasibility of installing independent meters to be registered to the CSP's Scheduling Coordinator are all issues for consideration.

Also to be considered are the roles and responsibilities around meter data management, data access needs between the LSE and CSP, and data and process flows specific to meter settlements data.

5.6.2. Stakeholder Comments

Blue Point Energy suggests that when AMI meters are present, both local aggregated net load and local aggregated resource load reductions should be reported to the ISO by the aggregator on a 5 minute basis. This assumes that the AMI will make net load information available to the aggregator on a 5 minute basis. This data would be subject to metering requirements similar to the current requirements for PL, and aggregation detail would need to be submitted on a daily or weekly basis. Blue Point Energy states that aggregators are already able to monitor their own load reductions, that their metering could be enhanced to perform in the proposed environment, and that utilities are rolling out AMI and could provide appropriate data without substantial investment.

EnerNOC identifies several issues for consideration, including: (1) minimum metering requirements (requirements for interval meters, or acceptability of load profiling for small customers), (2) timing requirements for providing meter data to the ISO after DR operations, (3) establishing measurement and verification protocols, (4) establishing a baseline methodology for measuring DR, and (5) performance measurement, possibly using the resolution of issues in a current CPUC proceeding for current utility programs.

NAPP suggests that the ISO should recognize the large investment by California utilities in Advanced Metering Infrastructure (AMI), and allow AMI metering solutions as a proxy for telemetry. NAPP suggests that the requirements energy or "capacity" resources should allow standard hourly or 15 minute interval data, whereas the ancillary services market should require metering solutions that provide actual 1-minute interval data. NAPP suggests that remote control and telemetry requirements can be barriers to participation and should not be a requirement for participation.

SCE states that the ISO has correctly articulated the issues related to metering, meter data management, and telemetry when the party serving the load and the party providing the DR are not the same entity, and that these issues will require significant stakeholder discussions including consensus business process mapping to resolve. SCE notes that while the number of Direct Access customers is relatively small, they represent a disproportionate share of SCE's DR participation, and participation rules need to allow a customer to be served by a non-utility LSE and a CSP.

5.6.3. Discussion

The ISO agrees with SCE's assessment that ultimately, addressing metering, meter data management, and telemetry will require significant stakeholder discussions, and that consensus business process mapping may be involved. The ultimate resolution of metering, meter data management, and telemetry issues most likely involves issues of CPUC jurisdiction as well as ISO market design, since the utilities' AMI programs are under CPUC oversight. However, the timing required for completing these processes extends well beyond the date when the ISO intends to provide enhancements to the MRTU Release 1 PL functionality.

The ISO has already established requirements for metering and telemetry for products that have been provided in the pre-MRTU market design and are provided under MRTU Release 1.[22] For these products, the ISO has not found differences in requirements that are created by adding the CSP to the types of market participants. These requirements are documented in the MRTU Release 1 Participating Load User Guide. In summary, interval metering is required for settlement of interval energy usage, but telemetry is required only for providers of ancillary services. If a DR resource participates in the DA energy market and limits its RT market participation to energy in the Hour-Ahead Scheduling Process (as allowed in the DDR and PDR models), only hourly interval metering is required. If a DR resource provides ancillary services, the ISO's operational requirements mandate the availability of telemetry, as described in the User Guide.[23] The ISO may consider alternatives to telemetry in the future, as it analyzes results of pilot programs using MRTU Release 1 PL functionality that the IOUs are implementing for summer 2009, but this is unrelated to the implementation of Direct Participation.

One significant difference in metering requirements may occur as Direct Participation is implemented. As discussed in section 3.6, settlement of energy, ancillary services, and RUC capacity all necessarily rely on a "baseline" calculation that estimates what the DR resource's energy usage would have been if it had not been dispatched as DR. If an end-use customer were not part of a PL resource, the LSE would be responsible for metering energy use, but this might not be interval metering. By adding DR response, the CSP is likely to use telemetry for monitoring its PL resources to establish its own knowledge of baseline energy usage, as well as for verifying their response to dispatches. Adding requirements for the CSP to maintain separate interval metering could add to the CSP's operating costs. It must be recognized that the baseline calculation is only an estimate of what would have occurred under different circumstances, and has some amount of error. The presence of this error in estimation is important in determining metering requirements, because metering itself has certain tolerances for error: revenue quality metering has an allowable 0.5% error, while telemetry has an allowable 2% error. When there inherently is error in the baseline calculation that is part of determining the amount of DR response that has actually been delivered, the difference between 0.5% and 2% error in metering is likely to not be significant. Therefore, the ISO suggests as a Straw Proposal for stakeholder discussion to allow the CSP to provide either telemetry-based data or revenue quality meter-based data to support settlements of DR response, and invites comments on the advantages and disadvantages of this concept.[24]

---

22 Meter data management for retail end-use customers is under CPUC jurisdiction. For purposes of the ISO markets, Scheduling Coordinators that represent loads must submit Settlement Quality Meter Data for financial settlements, but the ISO relies on Local Regulatory Authorities such as the CPUC to establish metering and meter data management requirements.

23 Regulation will have technical requirements for telemetry beyond a one-way information flow to the ISO, and spinning reserve may have technical requirements beyond those required for non-spinning reserve. The outcome of these issues depends largely on seeking WECC interpretation of the technical requirements for these services. Because actual participation in ISO markets appears likely to occur for energy storage systems before PL resources, and because the technical specifications for these services appears to be the same (i.e., requirements for non-generation resources regardless of technology), the development of these technical specifications will occur in a parallel stakeholder process for energy storage systems.

24 In the event that the CSP provides settlement quality meter data from revenue quality energy metering rather than telemetry, the ISO does not propose to establish requirements either that (a) the CSP must install separate metering or (b) the LSE must provide

As noted in section 5.5.1, as a Straw Proposal for further discussion, the ISO proposes that a PL that connects to the ISO Controlled Grid without other loads being served from the same grid takeout point must be a ISO Metered Entity, and otherwise PLs would be SC Metered Entities.

5.7. Settlement Issues

5.7.1. Background

As illustrated by the discussion in the Issue Paper, perhaps the most difficult issues in implementing Direct Participation involve financial settlements, since two market participants are now involved in serving the same end-use customers and revenues must be divided between them. Also, as previously noted, the ISO's DR programs require the aggregation of end-use customers within local areas, so that the ISO can use these resources effectively in the MRTU market's congestion management. The DDR model requires PLs to establish CLAPs for scheduling and settlement within Local Capacity Areas that are defined for Resource Adequacy requirements. The proxy generators in the PDR model must represent PLs within Sub-LAPs, some of which are smaller than Local Capacity Areas. The LMPs will vary between the Default LAPs that apply to most loads, and settlement issues include which price applies to scheduling of demand and which price applies to DR to dispatch by the ISO, which are not necessarily the same price.

Addressing these two fundamental settlement issues (how to allocate revenues between the LSE and CSP, and which price applies to demand scheduling vs. DR) involves a number of sub-issues. The Issue Paper listed the following as issues for consideration by stakeholders as they commented on the Issue Paper:

- How to prevent “double payments” as revenues are allocated to the LSE and CSP (i.e., the LSE's metered demand being reduced in RT settlements due to a load curtailment, and the CSP also receiving a payment for executing the load curtailment), and implications for settlement cash flows (direct settlements of Energy from ISO to CSP, or settlement by ISO to LSE followed by bilateral settlement between LSE and CSP)
- Any reconciliation required between the CSP and LSE
- Roles and responsibilities around settlement data, settlement validation, data retention, data management and data sharing
- Confidentiality issues between the LSE, CSP, and ISO
- Resolution of settlement disputes between the LSE and CSP. (Disputes by the LSE or CSP with ISO processes would use the existing ISO dispute resolution process.)

Some approaches to settlements involve comparisons of end-use customers' final metered demand to estimates of what their demand would have been if they were not participating in DR programs. If DR operations were only short-term events, verifying the response of the affected end-use customers could be simple. However, a review of the ISO's history of declared system emergencies shows that it is not unusual for these events to last from three to eight hours, and for declared transmission emergencies to last twelve or more hours. During this time, variations in most customers' normal demand can be expected, and even increases in demand during the time of a DR

its meter data to the CSP. This is an issue for which the LSE and CSP may negotiate a mutually acceptable solution, subject to requirements that may be adopted by the Local regulatory Authority (e.g., the CPUC). In the event that the CSP provides telemetry data for settlement, it must provide the ISO with access to real-time telemetry, which may be aggregated as described in the User Guide.

operation do not mean that the affected customers are not complying with the requested demand reductions below what their demand would otherwise have been. Thus, to determine compliance with DR schedules and dispatches as a basis for settlements, the ISO will establish methodologies for calculating baseline energy usage, through stakeholder and working group processes following the Order 719 compliance filing.

The considerations in establishing baseline methodologies were discussed in the Issue Paper and illustrated in the January 15 stakeholder meeting presentation, which is available at: http://www.caiso.com/2335/2335f3d540050.pdf.

5.7.2. Stakeholder Comments

Stakeholder comments on settlement issues commonly address the range of issues that are identified above (location for settlement of DR, allocation of revenues between CSP and LSE, and baseline calculations), among other issues.

AReM is concerned that the use of CLAPs will discourage customer participation in high-cost areas, and is interested in developing an alternative.[25] However, AReM is concerned that alternative approaches to settlements would require the ESP to pay for its full energy schedule, even if a DR program operated and the actual load was reduced.

Blue Point Energy suggests that bids should be settled by (1) paying the aggregator the cleared local aggregated resource load reduction, times the difference of the nodal RT energy price less the utility DA average price, (2) reimbursing the utility at the DA average price for the total of local aggregated resource load reductions, and (3) charging the utility for uninstructed deviations (the total RT load less DA load plus aggregated resource reductions). Thus, the utility would still pay for the energy to meet its load, and any DA over- or under-forecast of load, but would be reimbursed for total local aggregated resource reductions. Blue Point Energy states that there are several benefits to this method, including (1) allowing demand side resources to capture wholesale prices, and respond as a single resource through aggregation, with aggregator performance judged on the aggregated response, (2) allowing utilities to manage and forecast load much like they do today without more granular forecasting, and (3) enabling “smart grid” by making behind the meter demand side resources available for dispatch and ancillary services as directed in FERC Order 719. Blue Point Energy asserts that (1) there is no need for aggregator performance to be based on utility baseline calculations when metering is available, and (2) individual outage and performance measures will be less important than the more easily accessible performance measures for the aggregated resource, because aggregated resources will be combinations of many resources and thus more diverse.

CDWR-SWP is concerned that in an alternative that first schedules load at the Default LAP and then pays DR using a CLAP, the Baseline determination is a critical point of the design. Without an accurate and true Baseline, the amount of DR is difficult to determine, and this type of proposal would introduce “money machine” opportunities. A PL that is located where the LMP is higher than the Default LAP LMP could schedule “additional demand” to its Baseline Demand, and the corresponding DR could then offset the “additional demand” and receive a savings at the higher LMP. Without actually providing any DR, the PL could pay less or even earn revenue. On the other hand, a load at a location with a low LMP would be discouraged to provide any DR because its

[25] The ISO notes that use of CLAPs is part of the MRTU Release 1 Participating Load model, as the result of an extensive stakeholder process in 2005, the Board of Governors decision on refinements to the MRTU market design in October 2005, and FERC’s September 2006 order approving the MRTU design. The DDR design does not create the use of CLAPs, and the PDR model and the “partial participation” option in the DDR model provide alternatives to scheduling Participating Loads using CLAPs.

scheduled demand would be charged the higher DLAP LMP, and the DR would be paid the lower CLAP or nodal LMP. CDWR-SWP believes that the fundamental problem is the Demand settlement at DLAP LMP, which is a weighted average of nodal LMPs that hides price signals at individual locations for Demand to respond. CDWR-SWP proposes to replace the DLAP LMP design with settlement of both Demand and DR at nodal or CLAP LMPs. To eliminate the “money machine” opportunities, Demand and DR would be settled at the same location’s LMP.[26]

EnerNOC identifies that settlement issues include how CSPs are paid for their performance, what protocols or criteria apply to measurement and verification of DR data, how often this information is provided to the ISO, and in what format.

NAPP states that if an end user who participates in DR programs “earns” the retail rate savings in its utility bill and is therefore compensated by the ISO only for the incremental benefit, the settlement arrangement does not address the fact that the market rate would have been higher if not for the availability of the DR resource. NAPP suggests that the DR resource should be paid the full market energy price, without deducting the retail rate from that payment. NAPP notes that M&V of DR resources is an evolving area of focus across all ISO regions, and suggests that current rules should be assessed and addressed through a working group to implement a selection of methodologies that address the differences between customer load profiles, the factors that impact their profiles and the DR participation.

PG&E states that M&V protocols should not afford opportunities for gaming, such as allowing a DR provider to inflate his baseline at a higher price location while lowering his baseline at a lower price location and thus get paid for doing nothing. PG&E suggests that the ISO should coordinate any efforts to develop M&V protocols closely with the CPUC’s extensive work on estimating the load impacts of DR programs, especially for CPUC jurisdictional entities.

SCE agrees with the ISO Issue Paper’s statements that it is necessary to avoid “double payments” for DR program participation and wholesale bidding, and that the issues of settlement will require significant discussion. SCE’s comments suggest that the issues of scheduling and compensation for the newly proposed Direct Participation are very similar to the issues of scheduling and compensation for Direct Access customers that participate in the wholesale market through utility DR programs, which the utilities, ISO, and other stakeholders began to work through in late November 2008, and recommends that this effort should continue. SCE notes that previous ISO and CPUC workshops on metering, settlement and baseline issues have demonstrated that these issues are complex and potential solutions or approaches to resolution are wide and varied. SCE suggests that the California Load Impact Protocols being developed under the CPUC’s DR OIR process should be used wherever possible to facilitate consistency among market participants for determining load

[26] In additional comments, CDWR-SWP describes issues concerning clarify the obligations and limitations in use of Participating Load as a resource to the ISO, pursuant to filings in the ISO’s FERC proceeding regarding parameters to guide the market optimization in making adjustments to certain Non-Priced Quantities (the “Parameter Filing”). CDWR proposes that operational procedures and dispatches should ensure that Participating Loads are firm load (as firm as non-Participating Loads which are scheduled at LAP level) when not voluntarily offering DR, clearly specify the circumstances under which the ISO is authorized to use Participating Load, ensure that Participating Loads are treated on a nondiscriminatory basis with other loads when not offering DR, ensure that RT dispatch of Participating Load for energy from Contingency Only Ancillary Services shall occur only in the event of a true contingency, identify circumstances in which Participating Load may or may not be used in providing the services that it offers to ISO, and require that Participating Load shall not be dispatched for economic purposes except pursuant to that Participating Load’s bids. CDWR-SWP proposes that financial rates, settlement, and billing should ensure that Participating Load does not pay (through socialized cost allocation to loads) for the same services that it is providing, ensure that Participating Load is paid comparably to generators, ensure that Participating Load costs of providing service to ISO are covered, and hold Participating Load harmless from costs due to Parameter Tuning, nodal pricing, or any other adjustment or dispatch that has not been volunteered to the ISO. CDWR-SWP requests that legal tariff provisions and agreements should capture these principles in the Participating Load Agreement, limit ISO amendments to the Participating Load Agreement, allow loads to withdraw from Participating Load status, protect Participating Load from legal exposure for deviating from ISO dispatch or schedules, give Participating Load legal rights to decline dispatches or schedule adjustment, and commit that Participating Load will not be interrupted or adjusted except with consent.

impacts for retail participants. Of significant importance are the models used to develop baselines for resource performance, which will need consensus review by all market participants.

In addition, SCE and other parties have collaborated to understand the issues that they see in implementing DR programs for which the LSE is not the same entity as the developer of the DR programs, which is currently the IOUs under CPUC jurisdiction, and to develop a joint proposal to the ISO for resolving these issues, in the context of designing the PDR model. SCE has made presentations at the ISO's working group and stakeholder meetings to present the status of this work, and the most recent document detailing this work is available at http://www.caiso.com/2338/2338e5cc521b0.pdf. The ISO's review of this document is that it differs from the concepts for the PDR model that the ISO originally offered in summer 2008 in three ways:[27]

1. Settlement of the DR that is dispatched by the ISO using CLAP and Sub-LAP LMPs, instead of using the Default LAP LMP, to encourage CSPs to develop DR resources in locations with high LMPs,
2. Settlement of the dispatched DR through payments to the CSP (together with charges to the LSE for energy usage that would have occurred if DR bids were not dispatched), instead of through adjustments to LSE's demand schedule, and
3. Performance requirements that would need to be imposed for price-responsive energy, with additional data requirements, in order to support these settlement alternatives.

Since the January 15 stakeholder meeting on the ISO's Issue Paper, the ISO has met with SCE and other stakeholders to further develop all potential alternatives for settlements issues, and anticipates further developing these and other issues in working group meetings.

TURN supports an approach that unbundles the DR offered by a CSP for a DR aggregation from the load scheduled by the customers' LSE, for purposes of scheduling and settlement. This concept would continue to schedule and settle all LSE loads at the Default LAP level, while scheduling and settling the DR provided by CSPs at the local level, as a proxy generator.

5.7.3. Discussion

A factor that strongly influences the ISO's proposed resolution of settlement issues in this Straw Proposal is the current status of development of baseline methodologies for use in allocating financial payments among the ISO's market participants. Stakeholder comments indicate that market designs that depend strongly on baseline calculations take considerable time to develop and implement. This concern could lead to a conclusion that the initial implementation needs to use simplified requirements for use of baseline calculations. Depending on design of financial settlements, the baseline calculation can affect both the total revenue that is paid to DR (at the expense of market participants that are not involved in DR), and the allocation of revenues between the LSE and CSP. As discussed in section 5.7.1, the development of baseline methodologies is highly complex, which means that this task can be very time-consuming. Clear guidance cannot be obtained by examining the practices of other ISOs, because multiple methodologies are in use. The North American Energy Standards Board (NAESB) is working toward development of standards, but time is needed for completion of NAESB's work, and the NAESB work addresses what affected parties should include in their practices, but does not prescribe a methodology.

27 The document provided by SCE also have several mischaracterizations of the ISO's proposals, which the ISO listed in slide 9 of its presentation at the January 15, 2009, stakeholder meeting, available at http://www.caiso.com/2335/2335f3d540050.pdf.

Nevertheless, the ISO needs to have some sense of direction for its conceptual design for implementation of Direct Participation, as part of its compliance with Order 719, and enhancing the existing DR functionality is also needed for compliance with other FERC orders. That is, FERC has directed the ISO to implement scarcity pricing within 12 months after MRTU Go-Live, and the ISO's stakeholder process on scarcity pricing has identified the enhancement of DR in the ISO's markets as a requirement for scarcity pricing. Vendor development of software enhancements, followed by implementation and testing by the ISO and market participants, limits the available time for developing a baseline methodology.

At this time, the ISO believes that the appropriate path through these complex implementation issues is to work cooperatively with the CPUC. The CPUC has developed load impact protocols for measuring the impact of DR programs as a whole, and the ISO understands that protocols for event-specific settlements among market participants are currently being developed. Therefore, as this Straw Proposal analyzes alternatives for the other major topics concerning financial settlements (which price applies to demand scheduling vs. DR, and how to allocate revenues between the LSE and CSP), the ISO sees considerable advantage in starting with the protocols that the CPUC is developing, exploring alternatives that could minimize the impact among market participants of any errors in baseline calculations, and thereby having opportunities to gain experience with baseline calculations. As the ISO and its market participants gain experience with baseline calculations, the ISO can re-examine its initial design of baseline methodologies and financial settlements, and work with the CPUC to develop consistent methodologies in wholesale and retail markets.

5.7.4. Other Issues

CDWR-SWP recognizes that there are tradeoffs among DR design options when DR is dispatched at its nodal location but most demand is scheduled and settled at the Default LAPs, and recommends resolving these issues by scheduling and settling all demand at nodal locations or CLAPs. FERC's September 21, 2006, decision conditionally accepting the MRTU tariff has ordered the ISO to develop Sub-LAPs to replace the existing Default LAPs within three years of MRTU operation, and the ISO has stated in several filings to FERC since that decision that it is committed to comply with FERC's order. However, the ISO is not required to replace the existing Default LAPs at this time, and will plan a separate stakeholder process to develop its compliance to this portion of FERC's September 21, 2006, order. FERC has addressed the concerns stated in CDWR-SWP's additional comments, in its February 19, 2009, decision in docket ER09-240-000 (uneconomic adjustment policy). This decision notes that PL receives nodal treatment as opposed to zonal treatment resulted from positions previously advocated by CDWR-SWP, finds that PL is not similarly situated to other market participants, and rejects CDWR-SWP's assertion of undue discrimination. The ISO's responses to CDWR-SWP's comments in docket ER09-240-000 explained that the ISO's market design and CDWR-SWP's existing transmission contracts provide adequate assurance that CDWR-SWP's load will be served, and FERC's decision finds that CDWR-SWP's arguments that its status as PL could result in denial of transmission service or involuntary curtailments are misplaced. The ISO's compliance process for FERC Order 719 includes an examination of barriers to DR, which is separate from the current process for developing Direct Participation, and the concerns to be examined can include CDWR's remaining requests.

5.8. Performance & Compliance Evaluation

5.8.1. Background

There are two general aspects to monitoring and management of the performance of demand resources: general program monitoring to ensure that the ISO markets and market design are performing as intended, and response to non-performance by specific demand resources. The ISO as well as other entities will naturally be monitoring general program performance, and detail here is not necessary. The focus of this section is response to non-performance by specific demand resources.

5.8.2. Stakeholder Comments

EnerNOC identifies issues of performance management as including how underperformance is handled, whether there are penalties, whether credit provisions are triggered, and whether customers and CSPs performance would be de-rated due to non-performance.

5.8.3. Discussion

The DDR and PDR models that the ISO has described in its Draft Final Proposal on DDR and PDR design (http://www.caiso.com/2070/2070c79e59140.pdf) include no-pay provisions for ancillary services and RUC capacity payments, and compliance requirements for resource adequacy, which are in place in MRTU Release 1 and apply to all suppliers of these services. The requirements that are applicable to other Supply resources have already been developed over the past several years through the ISO's operational experience, and there is no apparent reason why they should not continue to apply equally to DR programs.

Comments by SCE during stakeholder discussions suggest that PL resources should be subject to the same performance requirements for compliance with energy dispatches as generation. Although the ISO tariff defines Uninstructed Deviation Penalties (UDP) for energy from generation, these provisions are not currently active, and the ISO would need to file a tariff amendment and receive a FERC order before these provisions could be activated. In addition, the existing tariff provisions explicitly exempt all loads from these requirements, including PLs.

In searching for analogies to other types of performance requirements that currently exist, as part of considering whether any performance requirements beyond the existing AS and RUC no-pay provisions, and Resource Adequacy requirements, one can observe that LSEs are currently subject to minimum scheduling requirements in the DA market, as a percentage of total demand. The minimum scheduling requirements expire when Convergence Bidding is implemented, which FERC has ordered to be implemented 12 months after MRTU Go-Live. Convergence Bidding allows market participants to submit "virtual" bids for demand or supply into the DA market, which will automatically be reversed in RT. The purpose of Convergence Bidding is to encourage similar scheduling outcomes between the DA and RT markets, by allowing virtual bidders to replace the bids of actual demand or supply if the entities that actually serve demand or supply fail to schedule accurately in the DA market. There is no requirement for virtual bidders to accurately anticipate the RT market conditions, because the difference between DA and RT market prices provides the necessary financial enforcement mechanism.

Given the explicit UDP exemption to all loads that is already in the ISO tariff, and the FERC requirement to implement Convergence Bidding 12 months after MRTU Go-Live, the ISO does not see needs for additional non-compliance penalties for price-responsive energy dispatched from DR resources, beyond the existing provisions that apply to AS, RUC, and RA capacity resources.

However, the ISO will enforce the existing provisions for DR resources just as it does for other market resources.

6. Conclusion and Summary

Based on the ISO's review of stakeholder comments submitted to date, the following principles appear to be appropriate as a Straw Proposal intended for stakeholder discussion. The reader should understand that these are not final proposals, and that the ISO's development of final proposals will occur only after stakeholder discussion and written comments.

6.1. Qualification

- The ISO does not find it necessary to either broaden its role beyond that of market operator, or to change either the existing requirements for market resources to be represented by Scheduling Coordinators. The ISO does not see needs for extensive revisions to the tariff provisions governing Scheduling Coordinators.
- When seeking to qualify a DR resource, the CSP must certify to the ISO that participation by its resource is not precluded by the Local Regulatory Authority, e.g., the CPUC. The eligibility of the DR resources themselves does not seem to be affected by whether they are operated by a CSP that is the same entity as the LSE, or by an independent CSP through Direct Participation.
- It is the CSP's role, not the ISO's, to create demand resource aggregations.
- The ISO's market recognizes market resources' operational constraints as part of bid submissions using DDR and PDR, but the ISO does not determine the resources' operational constraints.
- The utilities' retail programs include emergency response programs such as interruptible tariffs, but the ISO's markets do not have emergency response products. The ISO tariff already limits the participation of the same end-use customers in emergency response programs and PL resources, and the ISO does not see the addition of CSPs to the market as changing the existing tariff provisions.
- The ISO does not currently operate and is not currently developing a market for resource adequacy capacity, and instead works with Local Regulatory Agencies (such as the CPUC) to develop RA requirements that market participants must meet. The LRAs define which resources qualify as RA capacity.
- Only a single CSP will be allowed initially to represent the same end-use customer. This provision can be reconsidered after the market has experience with Direct Participation.
- The CSP should be subject to the same, existing credit requirements as other Supply resources.

6.2. Registration

- The following principles appear to be appropriate requirements for Direct Participation:
    - A DR resource can only be registered to one CSP / LSE at a time
    - The DR resource is registered to the correct CSP / LSE

- All registered DR resources are aware that they are registered with a specific CSP / LSE
    - Confirmation of any change of CSP / LSE is communicated to the DR resource, and the DR Resource affirmatively confirms that change
    - A DR resource who wishes to leave the DR resource pool confirms that it has been removed
    - The CSP / LSE's report to the ISO of DR capability is accurate and reflects the registered DR resource capacities.
    - Load schedules and DR bids are submitted using consistent load aggregations by the LSE and CSP, to the extent that a DR program requires such consistency.
- The ISO's existing processes for registering DR resources are documented in the MRTU Release 1 Participating Load User Guide, and provide a flexible structure for managing DR resources, and for providing the ISO with the information it needs to manage its markets without excessive needs for the ISO to track individual end-use customers.
- Each CSP is responsible for managing its DR resources and will see the financial impacts of any mismanagement in its final settlements. There appears to be no need for the ISO to develop complex systems for tracking individual end-use customers to actively manage the registration and confirmation process. Instead, market participants should be responsible for managing end-use customer registrations, pursuant to rules and processes that the ISO and CPUC will establish.
- LSEs as well as CSPs need to be aware of DR enrollments and schedule changes. The ISO's tariff will establish the principles for this data exchange, followed by development of implementation details in the Business Practice Manuals and Participating Load Users Guide. In actual operations, the CSP's enrollment of DR resources will require the CSP to identify the LSE to the ISO, so that the LSE can be notified of the DR schedule changes.

6.3. Scheduling

- Except for the presence of both the LSE and CSP as market participants, the basic functions of scheduling are not changed by the addition of the CSP as a market participant that is separate from the LSE.
- When the LSE and CSP are separate entities, scheduling functions that would be performed to schedule demand that if it were not participating in DR would remain with the LSE, but functions that exist because of participation in a DR program would be the CSP's responsibility.

6.4. Notifications

- Other than new needs to communicate MW quantities of demand schedules and dispatches to both the CSP and LSE, the ISO has identified no needs to change the existing notification mechanisms for communicating schedules in the DA market and dispatches in the RT market, and will continue to use the existing mechanisms as documented in the User Guide.
- LSEs as well as CSPs need to be aware of DR enrollments and schedule changes. The CSP needs to be aware of the amount of demand that is being scheduled by the LSE, when the CSP is using the DDR model. The ISO's tariff will establish the principles for this data

exchange, followed by implementation details in the Business Practice Manuals and Participating Load Users Guide.

6.5. Metering and Telemetry

- The ISO has already established requirements for metering and telemetry, which are documented in the MRTU Release 1 Participating Load User Guide and will continue to apply after Release 1. Interval metering is required for settlement of interval energy usage, but telemetry is required only for providers of ancillary services. If a DR resource participates only in hourly energy markets, only hourly interval metering is required.
- Although there are alternatives for the ISO's direct settlement of the energy resulting from DR directly with the LSE and CSP, bilateral arrangements between the CSP and LSE are an alternative for reallocation of the energy settlements between these entities. Regardless of the mechanism for energy settlement, the ISO's settlements for ancillary service and RUC capacity products are anticipated to be to the CSP. Settlement of ancillary service and RUC capacity relies on a "baseline" calculation that estimates of energy usage in the absence of the dispatched DR, which has some amount of error. Because there inherently is error in the baseline calculation, the ISO anticipates allowing the CSP to provide either telemetry-based data or revenue quality meter-based data to support settlements of AS and RUC capacity.
- Ultimately, metering, meter data management, and telemetry issues will require significant stakeholder discussions, which will continue as implementation issues after policy issues concerning ISO markets are resolved.
- As a Straw Proposal for further discussion, a PL that connects to the ISO Controlled Grid without other loads being served from the same grid takeout point would be a ISO Metered Entity, and otherwise PLs would be SC Metered Entities.

6.6. Settlement Issues

- Because "baseline" methodologies for calculating energy usage in the absence of the dispatched DR are used in allocating financial payments among the ISO's market participants, but will take considerable time to develop and implement, the initial implementation of market enhancements needs to use a set of initial requirements for use of baseline calculations, and then examine potential refinements over time. Settling the energy for DR dispatches at different locations, with different LMPs, than the underlying schedules requires greater precision in the baseline calculation for determining the amount of response, compared to direct settlement of DR as simply a capacity resource. Similarly, having the ISO responsible for allocation of savings between market participants requires greater precision in the baseline calculation than if the ISO settles all energy usage with the LSE and relies on the CSP and LSE to separately negotiate the allocation of savings. As the ISO and its market participants gain experience with baseline calculations, the ISO can re-examine its initial design of baseline calculations and financial settlements.
- The ISO recognizes that the PDR model's simplification of the DDR model's data requirements for CLAPs does not need to prevent PDR resources from earning their locational prices, if their operation does not raise the "gaming" concerns. The gaming concern involves DR participation that occurs in a significant number of hours, but programs that aggregate numerous customers are more likely to involve infrequent operations, and strategic modifications of baseline calculations appears to be less likely when an aggregation involves numerous customers. Therefore, the ISO is continuing to explore with market participants what conditions can allow demand to be scheduled under the PDR model at the

Default LAP while DR dispatches are settled using CLAPs, such as limited hours of operation (e.g., less than 200 hours per year) and establishment of predetermined bid prices that would not be expected to be exceeded in more than the limited number of hours, or robust baseline calculations.

- Allocation of savings between market participants involves complex trade-offs among multiple alternatives. The ISO will continue to work with the CPUC and stakeholders to develop sufficiently mature baseline methodologies to support ISO settlements. Based on adoption of a standard methodology, after receiving input from Local Regulatory Authorities, the ISO would proceed with settlements that allocate the DR savings to the CSP or divide the savings between the CSP and LSE, for example by reimbursing the LSE for its DA schedule that is curtailed by the CSP, and crediting the CSP with the balance. The ISO anticipates directly settling AS and RUC capacity payments with the CSP. This does not mean that revenues received by the CSP are limited to the capacity payments, because the CSP and LSE may negotiate a sharing of the energy revenues that are initially paid by the ISO.

6.7. Performance Management

- Given the explicit UDP exemption to all loads that is already in the ISO tariff, and the FERC requirement to implement Convergence Bidding 12 months after MRTU Go-Live, the ISO does not see needs for additional non-compliance penalties for price-responsive energy dispatched from DR resources, beyond the existing provisions that apply to AS, RUC, and RA capacity resources. However, the ISO will enforce the existing provisions for DR resources just as it does for other market resources.

7. Appendix A - Summary of Relevant Sections of Order 719 on Direct Participation

FERC Final Rule re Wholesale Competition in Regions with Organized Electric Markets (125 FERC ¶ 61,071) (issued in Docket Nos. RM07-19-000 and AD07-7-000 on October 17, 2008) (hereinafter "FERC Oct 17 Final Rule"). The FERC Oct 17 Final Rule states in pertinent part (numbers reflect Paragraphs numbering of the FERC Final Rule:

> 154. The Commission adopts in this Final Rule the proposed rule to require RTOs and ISOs to amend their market rules as necessary to permit an ARC to bid demand response on behalf of retail customers directly into the RTO's or ISO's organized markets, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate. We find that allowing an ARC to act as an intermediary for many small retail loads that cannot individually participate in the organized market would reduce a barrier to demand response. Aggregating small retail customers into larger pools of resources expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability. We also agree with commenter's that this proposal could encourage development of demand response ….
>
> 155. … In the NOPR, the Commission sought to address the concerns of state and local retail regulatory entities by proposing to require that an ARC may bid retail load reduction into an RTO or ISO regional market unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate in this activity. The Commission's intent was not to interfere with the operation of successful demand response programs, place an undue burden on state and local retail regulatory entities, or to raise new concerns regarding federal and state jurisdiction, as some commenter's argue. As described above, we clarify that we will not require a retail electric regulatory authority to make any showing or take any action in compliance with this rule. Rather, this rule requires an RTO or ISO to accept a bid from an ARC, unless the laws or regulations of the relevant electric retail regulatory authority do not permit the customers aggregated in the bid to participate.
>
> 157. With regard to LPPC's request that ARCs not bid on behalf of load served by ARCs that are not RTO or ISO members, SMUD's request for clarification that loads outside of an RTO's or ISO's control area would not participate in demand response programs, and TAPS's comment that the proposal should not require a change to an existing retail load reduction program, the continuing role of the relevant retail electric regulatory authority adequately addresses these concerns.
>
> 158. Further, we agree with the comments that, because each region's market design is different, it is important to permit each RTO or ISO to design ARC provisions that account for these differences. Therefore, instead of developing pro forma language or requiring RTOs and ISOs to make detailed generic market rule amendments, we direct RTOs and ISOs to amend their tariffs and market rules as necessary to allow an ARC to bid demand response directly into the RTO's or ISO's organized market in accordance with the following criteria and flexibilities that remain largely unchanged from those advanced in the NOPR:
>
> a. The ARC's demand response bid must meet the same requirements as a demand response bid from any other entity, such as an ARC. For example:

i. Its aggregate demand response must be as verifiable as that of an eligible ARC or large industrial customer's demand response that is bid directly into the market;

ii. The requirements for measurement and verification of aggregated demand response should be comparable to the requirements for other providers of demand response resources, regarding such matters as transparency, ability to be documented, and ensuring compliance;

iii. Demand response bids from an ARC must not be treated differently than the demand response bids of an ARC or large industrial customer.

b. The bidder has only an opportunity to bid demand response in the organized market and does not have a guarantee that its bid will be selected.

c. The term "relevant electric retail regulatory authority" means the entity that establishes the retail electric prices and any retail competition policies for customers, such as the city council for a municipal utility, the governing board of a cooperative utility, or the state public utility commission.

d. An ARC can bid demand response either on behalf of only one retail customer or multiple retail customers.

e. Except for circumstances where the laws and regulations of the relevant retail regulatory authority do not permit a retail customer to participate, there is no prohibition on who may be an ARC.

f. An individual customer may serve as an ARC on behalf of itself and others.

g. The RTO or ISO may specify certain requirements, such as registration with the RTO or ISO, creditworthiness requirements, and certification that participation is not precluded by the relevant electric retail regulatory authority. [fn **212** The RTO or ISO should not be in the position of interpreting the laws or regulations of a relevant electric retail regulatory authority]

h. The RTO or ISO may require the ARC to be an RTO or ISO member if its membership is a requirement for other bidders.

i. Single aggregated bids consisting of individual demand response bids from a single area, reasonably defined, may be required by RTOs and ISOs.

j. An RTO or ISO may place appropriate restrictions on any customer's participation in an ARC-aggregated demand response bid to avoid counting the same demand response resource more than once.

k. The market rules shall allow bids from an ARC unless this is not permitted under the laws or regulations of relevant electric retail regulatory authority.

159. … Further, in response to those who ask us to require in this rule (1) that each RTO or ISO should be required to demonstrate net benefits of its program, (2) that bids should be aggregated on a local basis, and (3) that so called "double payment" should be either required or prohibited, we decline to do so here. Such issues are more appropriately addressed by each region in its compliance filing if it chooses to do so.

161. In accordance with NYISO's recommendation, the Commission will clarify that its regulatory reference in § 35.28 (g)(ii) to "organized market" has the same meaning as proposed under (g)(i) and that ARCs are to comply with any necessary technical requirements under the RTOs or ISO's tariff.