Reliability Demand Response Product

Draft Final Proposal

Version 1.0

Prepared for
The Reliability Demand Response Product
Stakeholder Initiative

September 1, 2010

Revisions Based on the Straw Proposal			
Version	**Date**	**In Response to:**	**Revisions**
1.0	08/02/10 to 09/01/10	N/A	**General** • General document clean up for readability and language refinement throughout the document, including punctuation, capitalization, etc.
		Various	**Executive Summary** • General updates to reflect changes to the RDRP, including the concept of "dual participation" and removal of the performance incentive element. • Added footnote #4 to add clarity around a RDRP resource's sustained response period.
		DRA PG&E	**Product Description- 3.1 Overview** **Settlements- 6.1 Overview & 6.3.2 Default Load Adjustment** • Removed following statement in acknowledging that compensatory issues between the Demand Response Provider and load-serving entity: *In this way, the load serving entity neither benefits from, nor is harmed by, the load curtailment actions of the DRP that is providing demand response services to that load-serving entity's customers.*
		CDWR Dynegy	**Product Description- 3.1 Overview** • Added additional detail and description concerning the possible uses of the RDRP • Added Footnote #11 to clarify pricing rules of RDRP resources
		PG&E	**Product Description- 3.4 ISO Market and Model** • With addition of dual participation feature, removed the following statement: *… however, unlike Proxy Demand Resources, due to availability limits, RDRP resources are only suitable for participation in real-time, not day-ahead, when critical and stressed system conditions can occur that might precipitate their eligible use and activation. Thus, RDRP resources are only eligible to participate in the ISO's real-time market.*
		CAISO	**Product Description- 3.4.1 Constrained Output Generation Model** • Added language (and footnote 3): *The ISO will incorporate the COG model, <u>or similar functionality</u>, into the RDRP design so that the ISO can more easily accommodate RDRP resources that require a discrete or "block" dispatch.*
		CAISO	**Product Description- 3.4.1.1.1 Day-Ahead Market Participation** • Added this section to clarify that the ISO will not enforce a discrete megawatt clearing of energy in the day-ahead market for RDRP COG resources. Thus, all RDRP resources, including those electing the COG option, may submit multi-segment energy bids in the day-ahead market. In the real-time, the ISO will enforce the discrete or "non-marginal" dispatch; therefore, RDRP COG resources will only be allowed to submit a single-segment energy bid into the hour-ahead scheduling process.
		CAISO	**Product Description- 3.4.1.2 Calculated Hourly Minimum Load Costs** • Added clarifying language as underlined: *Under the RDRP COG option, a RDRP resource must submit <u>a single energy bid segment</u> bid for real-time energy into the hour-ahead scheduling process in the range of 95% Bid Cap ≤ Bid ≤ Bid Cap.*

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		SCE	**Product Description- 3.5.2 Residual Unit Commitment** • Updated language to reflect dual participation nature of RDRP, and explain inability of RDRP resources to participate in the RUC process
		SCE	**Product Description- 3.5.3 Must Offer Obligation** • Modified paragraph as follows to address concerns around the existing language in ISO tariff section 40.6.4.3.2: *Further, RA qualifying RDRP resources will have special designation like that of Hydro and Non-Dispatchable Use-Limited Resources as specified in ISO tariff section 40.6.4.3.2, but without an obligation to bid in the day-ahead market. During the ISO tariff development stage for the RDRP, the ISO will determine whether or not to weave RDRP resources into 40.6.4.3.2 or, if necessary, craft a new sub-section entirely.*
		CAISO	**Registration- 4.2.1 Registration Overview** • Additional section added to introduce the RDRP registration process.
		FERC PDR Order CAISO	**Registration- 4.2.3 Resource Registrations** • Modified underlined language: *The registrations under a RDRP resource must be within the same Sub-LAP and served by the same load-serving entity. All registrations will have an effective start and end date that must be <u>validated</u> by the load-serving entity and utility distribution company through the ISO's Demand Response System <u>within 10-business days</u>.*

		CAISO	**Scheduling & Bidding- 4.3.1 Bidding Requirements**
			• Included/clarified in the rules that apply to RDRP resources:
			    ○ *Multi-segment energy bid curve eligible for all RDRP resources in the day-ahead market*
			    ○ *Day-ahead energy bids will not be constrained to be in the range of the ISO bid cap and 95% of the bid cap as are energy bids in the real-time*
			    ○ *Single segment energy bids must be submitted in the real-time for RDRP COG resources; multi-segment bids can be submitted for all other RDRP resources in real time*

		CAISO	**Notification- 4.4.1 Day-Ahead Market Clearing** • Added language to clarify that a RDRP resource that offers energy in the day-ahead market will clear the day-ahead market as a marginal resource. In other words, RDRP resource that elects the COG option will not clear the day-ahead market for a discrete or block quantity if it happens to be the marginal resource in the day-ahead market. A discrete or "non-marginal" dispatch is associated with real-time energy dispatches. • Clarified that day-ahead market results are published through the ISO's CMRI system
		PG&E Dynegy	**Notifications- 4.4.2 Real-Time Dispatch** • Reworded paragraph to address issue of notification between the ISO and the PTO and to reflect where this will be documented: *The ISO will update and maintain its emergency operating procedures and processes, including updates to its emergency operating procedure E-511- Interruptible Load Programs- to incorporate the RDRP. Notifications between the ISO and the Participating Transmission Owners will be as specified in this procedure.* • Added additional detail about the real-time dispatch of RDRP resources.
		CAISO	**Notification- 4.4.3 Exceptional Dispatch** • Added this section to clarify the ISO's position on Exceptional Dispatch of RDRP resources.

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		CAISO	**Metering** • Modified this section to clarify that settlement quality meter data must be submitted, along with the supporting Baseline Adjustment Window data, only after an event has occurred for RDRP resources that only offer energy in the real-time; otherwise, daily submission is required for RDRP resources that offer day-ahead energy.
		Stakeholder Meeting SCE SDG&E	**Performance & Compliance- 5.1 Testing** • Changed word: "unnoticed" to "unannounced" • Added underlined: Test events will not count toward the RDRP availability limit of 15 events and/or 48 hours per RDRP Term nor will the Performance Incentive apply. The ISO will share test event results with the RDRP resource's applicable Local Regulatory Authority. • Based on stakeholder feedback and conflict with retail tariff, modified language to affirmative: Test events will count toward the RDRP availability limit of 15 events and/or 48 hours per RDRP Term (previously said "will not count"). • Added clarification as underlined: The ISO's preference will be to rely on actual events to determine the availability and performance of RDRP resources to avoid the burden of a test event on end-use customers; however, if no events have been called within the year, then the expectation is one test event will be performed annually, toward the end of a RDRP Term, to determine RDRP resource availability and performance.
		PG&E SDG&E SCE Dynegy	**Performance & Compliance- 5.2 Performance Incentive (Removed)** • Removed Performance Incentive section, including other references throughout the document. • Replaced section with reference to RDRP availability standards to be developed under the Standard Capacity Product Initiative.
		CAISO PG&E SCE	**Settlements- 6.2.2 Baseline Type II- Proxy Meter Data** • Added language to specify a process for reviewing and approving methods to derive Proxy Meter Data
		CAISO	**Settlements- 6.2.3 Other Baseline Types** • Additional language added to explain that any new baseline methodologies to be employed by the ISO will require an ISO tariff amendment and FERC approval.
		Stakeholder Meeting	**Settlements- 6.2.5 Events Considered in the Baseline Calculation** • Per stakeholder feedback, copied details from section 4.4.4-Outage Reporting into section 7.2.5
		N/A	**Stakeholder Initiative Process- 7.1 Milestones & 7.2 Schedule** • Updated schedule to reflect a more realistic tariff development and FERC approval process

		N/A	**Attachment 1: Terms & Definitions**
			• Added the following terms and definitions:
			    o CAISO Controlled Grid
			    o Day-Ahead Market
			    o Load Point Adjustment
			    o System Emergency
			    o Imbalance Energy
			• **Removed the following terms and definitions:**
			    o SLIC; revised term "SLIC" in document to ISO outage management system

Revisions Based on the Straw Proposal			
		N/A	**Attachment 2: RDRP Product Design Matrix** • Various updates made to the matrix to reflect RDRP changes, including removal of references to the Performance Incentive, Dual Participation attributes, etc.

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1 Executive Summary

The Reliability Demand Response Product (RDRP) is a wholesale demand response product that enables emergency responsive demand response resources to integrate into the California ISO market and operations. The RDRP concept is borne out of a multi-party, cross-industry CPUC approved settlement agreement that resolves a myriad of issues concerning the quantity, use, and the resource adequacy treatment of retail emergency-triggered demand response programs.[1] RDRP is scheduled for release by the ISO in the spring of 2012.

As directed by the settlement agreement, the RDRP design ensures compatibility with, and the integration of, existing retail emergency-triggered demand response programs, such as interruptible load programs, direct-load control programs like air-conditioning cycling, and agriculture pumping programs. The RDRP design will allow RDRP resources to offer energy economically in the day-ahead market, and any remaining uncommitted capacity thereafter bid as energy in the real-time through the ISO's hour-ahead scheduling process. [2]

The RDRP is designed to integrate large-single or aggregated demand response resources that may be configured to offer energy economically in the day-ahead market and, as a minimum requirement, can respond to a reliability event for the delivery of "reliability energy" in real-time. Such dispatches are expected infrequently and with limited notice under certain and stressed system conditions as specified in ISO Emergency Operating Procedures.

Specifically, the RDRP has multiple reliability-only eligible uses, including 1) for system emergencies, including transmission emergencies on the CAISO Controlled Grid and for mitigating imminent or threatened operating reserve deficiencies, and 2) for resolving local transmission and distribution system emergencies.

Like other resources in the ISO market, RDRP resources will have a unique resource ID, must respond to dispatch instructions, and will be modeled like a supply resource relying on the functionality and infrastructure designed for the ISO's recently implemented Proxy Demand Resource product. And like Proxy Demand Resources, RDRP resources will be eligible to set the locational marginal price. As an additional feature, the ISO will incorporate the Constrained Output Generator model to enable a discrete dispatch capability of RDRP resources.[3] This feature is intended to help ease the integration of

[1] CPUC final decision approving the settlement agreement can be found here: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/119815.htm

[2] Here the reference to the hour-ahead scheduling process is to the market where real-time bids and schedules are submitted, and should not be confused with the ability for the ISO to pre-dispatch certain hourly resources (e.g., inter-ties) as part of the hour-ahead scheduling process.

[3] The ISO will develop the capability to issue a discrete, non-marginal dispatch to RDRP resources. The existing Constrained Output Generator functionality is currently best suited to deliver this capability;

existing retail emergency-triggered demand response programs that have a "Firm Service Level" load curtailment construct where a demand response resource must curtail its demand to a specified megawatt quantity regardless of its electricity consumption at deployment; thus, firm service level configured resources would benefit from the ability to receive a discrete megawatt quantity dispatch from the ISO.

Like a Proxy Demand Resource or a generation resource, the real-time energy bid associated with a RDRP resource will convey both a price and other biddable attributes. Once system conditions occur that require the dispatch of RDRP resources, the ISO will release the RDRP resources to be evaluated for commitment by the ISO's real-time dispatch application and, if committed, dispatched by the ISO's Automated Dispatch System based on the RDRP resource's bid and resource parameters. The length of dispatch (aka the *Sustained Response Period*) of a RDRP resource may be up to four (4) hours per event and a RDRP resource cannot have a minimum run time of greater than one (1) hour.[4] Once the condition that precipitated the dispatch of the RDRP resources is resolved and system conditions have returned to normal, the RDRP resources will be returned to their "emergency-only" status and an "event" and "event duration" will be recorded and counted against the total RDRP eligible availability limits of 15 and/or 48 hours within any six (6) month RDRP Term.[5] The availability limits for the RDRP generally align with the historical use limits of retail emergency triggered demand response programs.

RDRP resources will be settled through the ISO market like Proxy Demand Resources, employing North American Energy Standards Board methodologies Baseline Type I (where interval meter data exists), or Baseline Type II (where interval meter does not exist). And like Proxy Demand Resources, the load-serving entity and the Demand Response Provider can be separate entities; thus, the RDRP, like Proxy Demand Resources, will employ the Default Load Adjustment mechanism. This settlement mechanism adds back the actual performance of the RDRP resource to the meter quantity of the respective load-serving entity in the ISO's uninstructed pre-calculation, resulting in an "adjusted" metered demand value.

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however, the ISO may explore and deploy a different, more robust option that provides this same functionality and similar feature set during the development of the RDRP.

[4] The minimum qualification requirement for a RDRP resource is to have a sustained response period of four hours; however, if a RDRP resource can sustain a longer duration outage, as specified in the ISO masterfile as the resource's maximum run time, say six hours, then the ISO's real-time dispatch application will know that that RDRP resource is available for up to six hours.

[5] An "event" is counted against the total number of eligible events and hours for a RDRP resource only if and when the RDRP resource is actually dispatched by the ISO or is triggered by the Demand Response Provider for a local transmission or distribution emergency and simultaneously reported to the ISO through the ISO's outage reporting system.

2 Background

2.1 Settlement Agreement

Development of the RDRP as a new ISO demand response product was a key element and outcome of a settlement agreement that resolved a myriad of issues concerning the quantity, use, and the resource adequacy treatment of retail emergency-triggered demand response programs among the settling parties. [6]

The settlement agreement was an outcome of the CPUC's rulemaking of January 25, 2007 and is part of the CPUC's "continuing effort to develop effective demand response (DR) programs" and its consideration of "modifications to DR programs needed to support the California Independent System Operator's efforts to incorporate DR into market design protocols."[7] Specifically, on July 18, 2008, the CPUC initiated Phase 3 of this rulemaking to address the "operation of the investor-owned utilities' emergency-triggered DR programs in the future electricity wholesale market."[8]

After participating in two-Phase 3 workshops and prior to conducting a third workshop, the parties requested additional time to explore possible resolution of the issues through settlement. On January 20, 2010, the settling parties provided "notice" of a settlement conference to the CPUC. A settlement conference was subsequently convened on January 29, 2010. Participating parties were the settling parties and the Alliance for Retail Energy Markets (AReM). The settling parties met on numerous occasions which finally resulted in a settlement in principle. On February 22, 2010, the settling parties filed a joint motion asking for the adoption of a settlement to be filed in the proceeding.

On June 24, 2010, the CPUC issued it final decision (D.10-06-034) approving the settlement agreement in its entirety, making the following summary remarks:

> *In broad terms, the Settlement transitions many of the current reliability-based and emergency-triggered demand response programs into price-responsive demand response products. In addition, it reduces the amount of reliability-based and emergency-triggered demand response programs that count for Resource Adequacy from the current 3.5% of system peak to 2% of system peak in 2014. …*
>
> *Under the Settlement, the reliability-based and emergency-triggered demand response programs will be changed to become more useful.[9] Most importantly, the reliability-triggered demand response program will be triggered prior to the*

[6] The settling parties include the CAISO, PG&E, SCE, SDG&E, TURN, DRA, EnerNOC, and CLECA.

[7] Order Instituting Rulemaking (R.) 07-01-041 (January 25, 2007) at 1.

[8] *Assigned Commissioner's and Administrative Law Judge's Amended Scoping Memo and Ruling*, July 18, 2008, at 1.

[9] Consideration of the transition to the new reliability-triggered/price-triggered demand response program will begin in the Investor Owned Utilities' 2012-2014 demand response program cycle applications that are due in January 2011, and these new demand response products are subject to Commission review at that time.

California Independent System Operator's canvassing of neighboring balancing authorities for energy or capacity. This new practice would eliminate the anomalous treatment whereby emergency-triggered demand response counts for Resource Adequacy yet, unlike all other power that counts for Resource Adequacy, the California Independent System Operator currently procures costly "exceptional dispatch energy or capacity" before using this energy resource, a practice that has led to charges that ratepayers "pay twice" for this power.

The Settlement also permits the development of new reliability-based demand response products, but any product eligible for a Resource Adequacy payment would be subject to the Resource Adequacy cap mentioned previously and review by the Commission.[10]

Finally, the settlement agreement outlines that the ISO will seek ISO Board approval for RDRP in November 2010, build the product in 2011, and release RDRP in the spring of 2012.

3 Product Description

RDRP is a wholesale demand response product that enables emergency responsive demand response resources to integrate into the ISO market and operations. The RDRP design must comply with the:

1. CPUC approved multi-party settlement agreement
2. NAESB measurement and verification standard
3. ISO market and models

Following is a description of RDRP and how these three elements impact the product's design.

3.1 Overview

The RDRP design is to be compatible with, and enable the integration of, existing retail emergency-triggered demand response programs, such as:

- The IOUs' Interruptible load programs, e.g. Base Interruptible Program or "BIP"
- Direct-load control programs, e.g. SCE's Summer Discount Plan
- Agriculture and interruptible pumping program, e.g. SCE's AP-I program

RDRP resources can be developed through any Demand Response Provider, and once registered and approved, can be scheduled with the ISO through a scheduling coordinator, independent of the load's load-serving entity; thus the Demand Response Provider and the load-serving entity can be separate and distinct entities. So in addition to integrating retail emergency response programs, the RDRP is designed to enable the integration of a Demand Response Provider's large-single or aggregated demand

[10] See *Decision Adopting Settlement Agreement on Phase 3 Issues Pertaining to Emergency Triggered Demand Response Programs*, issued June 24, 2010 (D.10-06-034), Pg. 1-3.

response resources that may be configured to offer energy economically in the day-ahead market and, as a minimum requirement, can respond to a reliability event for the delivery of "reliability energy" in real-time. It is expected dispatch of RDRP resources will be infrequent and with limited notice under certain and stressed system conditions as specified in ISO Emergency Operating Procedures.

More specifically, the Reliability Demand Response Product has multiple reliability-only eligible uses, including for:

1) System emergencies:
    a. Transmission emergencies
       For example, the loss of a transmission asset that is part of the CAISO Controlled Grid
    b. Mitigating imminent or threatened operating reserve deficiencies
       Specifically, the ISO may access RDRP resources as specified in its Emergency Operating Procedure E-508B, at a Warning Notice, prior to the ISO having to seek Exceptional Dispatch energy/capacity from other Balancing Area Authorities
2) Local transmission and distribution system emergencies:
   For example, to resolve a utility distribution circuit overload or to maintain a piece of electrical equipment within its emergency rating

To qualify under the RDRP, a RDRP resource must be capable of delivering reliability energy in real-time, reaching its full curtailment in no longer than 40-minutes, and the resource must be dispatchable by the ISO's Automated Dispatching System (ADS) within a geographic location, i.e. a Sub-Load Aggregation Point (Sub-LAP), and for a specified megawatt quantity. The megawatt quantity that is available from a RDRP resource during any particular hour is submitted to the ISO by the scheduling coordinator of the Demand Response Provider in the form of an hourly energy bid offered into the hour-ahead scheduling process in the range of the ISO bid cap and 95% of the bid cap. A bid range will enable a scheduling coordinator to use bid costs as a means to prioritize the dispatch of RDRP resources.

Like other resources in the ISO market, a RDRP resource will have a unique resource ID and will be modeled like a supply resource relying on the functionality and infrastructure designed for the ISO's Proxy Demand Resource product. And like Proxy Demand Resources and generators, RDRP resources will be eligible to set the locational marginal price.[11] As an added feature, the ISO will incorporate the Constrained Output Generator (COG) model and feature set into the RDRP to enable a discrete dispatch capability. The COG feature is intended to help ease the integration of existing retail emergency-triggered demand response programs that have a Firm Service Level (FSL) load curtailment construct and require a discrete megawatt quantity dispatch.

[11] RDRP resources follow the same pricing rules, including the ability to set the locational marginal price, as a generator. No special pricing rules are triggered as a result of dispatching RDRP resources. Only special bidding rules apply to RDRP resources, i.e. they must bid between the applicable cap and 95% of the cap.

Like a Proxy Demand Resource or a supply resource, the bid associated with a RDRP resource will convey both price and other biddable attributes. Once system conditions occur that enable the dispatch of RDRP resources, the ISO will release the RDRP resources to be evaluated for commitment by the ISO's real-time dispatch application and, if committed, dispatched by the ISO's Automated Dispatch System (ADS) based on the RDRP resource's bid and resource parameters. The length of dispatch (aka the *Sustained Response Period*) of a RDRP resource may be up to four (4) hours per event and a RDRP resource cannot have minimum run time of greater than one (1) hour. Once the condition that precipitated the dispatch of the RDRP resources is resolved and system conditions have returned to normal, the RDRP resources will be returned to their "emergency-only" status and an "event" (#) and "event duration" (*hours*) will be recorded and counted against the total RDRP eligible availability limits of 15 and/or 48 hours within any six (6) month RDRP Term. The availability limits for the RDRP generally align with the historical use limits of retail emergency triggered demand response programs. An "event" is counted against the availability limits, which is the total number of eligible events and/or hours for a RDRP resource only if and when the RDRP resource is actually dispatched by the ISO or is triggered by the Demand Response Provider for a local transmission emergency and simultaneously reported to the ISO through the ISO's outage reporting system.

A six (6) month RDRP Term enables the participation of both seasonal and annual interruptible load resources and provides a reasonable length of time for establishing and evaluating availability limits, i.e. 15 events and/or 48 hours per RDRP Term. The RDRP Term would be opt-out, i.e. a resource would automatically roll-over into the next RDRP Term, unless flagged not to do so, resetting the availability limits without any additional effort necessary on the part of the Demand Response Provider. The RDRP Terms proposed are May to October and November to April.

As specified in the settlement agreement and as previously explained, the RDRP has multiple reliability-only uses. If a RDRP resource is dispatched for local transmission or distribution reasons, the scheduling coordinator for the RDRP resource will promptly inform the ISO through the ISO's outage reporting system to ensure that the ISO is aware of the RDRP resource dispatch, knows the intended megawatt quantity of the dispatch (so that the ISO can consider the dispatches potential impact on reliability), and can record the "event" for counting/accounting purposes.

RDRP resources will be settled through the ISO market, employing NAESB methodologies Baseline Type I (where interval meter data exists), or Baseline Type II (where interval meter does not exist) for direct load control type programs. And like Proxy Demand Resource, where the load-serving entity and the Demand Response Provider can be separate entities, the RDRP will employ the Default Load Adjustment mechanism. This settlement mechanism adds back the actual performance of the RDRP resource to the meter quantity of the respective load-serving entity in the ISO's Uninstructed Imbalance Energy pre-calculation, resulting in an "adjusted" metered demand value.

A detailed RDRP Product Design Matrix can be found in Attachment 2, which lists the attributes of the RDRP.

3.2 Settlement Agreement Design Principles

The settlement agreement set forth specific design principles the RDRP. Following is a list of these design principles:

- Compatibility with existing retail emergency-triggered DR programs
- Meet minimum operating requirements and technical requirements, including max availability limits
- Not "price responsive," but economically dispatched at a strike price once available for dispatch as documented in ISO Emergency Operating Procedures
- Recognize participating customers have a high "strike price" that is well above the running cost of conventional supply-side resources
- Will help mitigate, or limit the duration of, scarcity pricing events
- Allow for up to one test event per year to ensure compliance and performance
- Has multi-reliability uses: system emergencies and local transmission emergencies
- Available to all Demand Response Providers
- Resource Adequacy qualification and counting subject to the applicable Local Regulatory Authority
- Settled through the ISO market; any other incentives/payments are the prerogative of the Local Regulatory Authority
- Dispatchable by location and megawatt quantity

Although not explicitly stated in the Settlement Agreement, the ISO includes the following design principle as fundamental to the product:

- RDRP resources are eligible to set the locational marginal price

3.3 NAESB Measurement & Verification Standard

FERC ordered each independent system operator and regional transmission operator to comply with and to revise its tariff to incorporate (by reference) the standard known as "*Business Practices for Measurement and Verification of Wholesale Electricity Demand Response*" adopted by the Wholesale Electric Quadrant of the North American Energy Standards Board (NAESB). This standard relates to the measurement and verification of demand response products and services in wholesale electric energy markets. Compliance with the standard was required on May 24, 2010 by the terms of FERC Order No. 676-F (Docket No RM05-5-017) 131 FERC ¶ 61,022. P 43 April 15, 2010.[12]

[12] As permitted by FERC Order No. 676-F, the ISO will submit a tariff amendment to FERC amending California ISO tariff section 7.3.3, NAESB Standards to include this measurement and verification standard as part of an unrelated tariff filing prior to December 31, 2010.

The ISO's RDRP must be designed in compliance with this measurement and verification standard which supports the measurement and verification characteristics of demand response products and services administered for application in the ISO market, subject to the ISO tariff as filed and approved by FERC.

The NAESB measurement and verification standard is intended to provide a common framework for describing demand response in the wholesale electricity markets by:

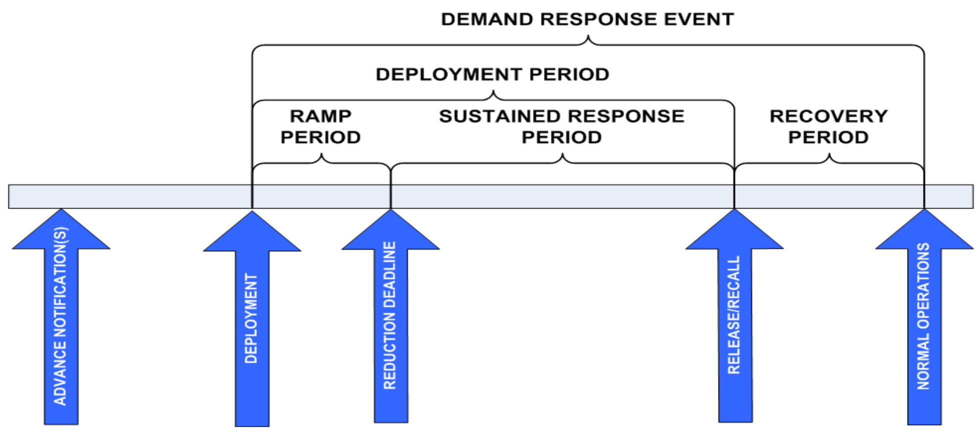
- Establishing common terms and definitions;
- Conveying understandable measurement and verification requirements for demand response products; and,
- Providing criteria to enable the system operator to accurately measure the performance of demand response resources.

Three noteworthy aspects of the NAESB measurement and verification standard that are most applicable to the RDRP are:

1. The type of demand response service provided:
   - ➢ Specifically-- Energy Service
2. The performance evaluation methods to be employed:
   - ➢ Specifically-- Baseline Type I & Type II
3. The standard terms and definitions applicable to the RDRP
   - ➢ Specifically—see Attachment 1: Terms & Definitions[13]

Further, the NAESB measurement and verification standard provides a framework for describing the timing of a demand response event. The ISO will enable RDRP resources to be modeled such that it fits into the timing framework as illustrated below in Figure 1.

Figure 1: Timing of a Demand Response Event[14]



[13] If the term was taken from the NAESB measurement and verification standard, the definition will be noted as such by use of the word "(NAESB)" at the end of the definition.
[14] Illustration from the NAESB Business Practices for Measurement and Verification of Wholesale Electricity Demand Response, Pg. 7.

For instance, the RDRP will enable a RDRP resource to specify a start-up time and a ramp rate, which when combined, will be limited to 40-minutes for a RDRP resource to reach its max curtailment capability (or PMax value). This 40-minute time limit provides sufficient flexibility for each RDRP resource to uniquely specify its advance notification time and ramp period. The ISO and Demand Response Provider can translate these values, based on the RDRP resources PMax, into an equivalent start-up time and ramp rate for that RDRP resource.

3.4 ISO Market & Models

RDRP resources will be modeled and settled as generators, the same as Proxy Demand Resources. RDRP resources will be eligible to bid energy, in the form of an economic load reduction in the day-ahead market, and any remaining uncommitted capacity is to be bid as energy in the real-time. RDRP resources will not be allowed to offer ancillary services or residual unit commitment capacity in the day-ahead market. The ISO's software and systems cannot manage a resource whose real-time energy bid co-mingles energy that is dispatchable under different operating conditions and scenarios, as would be the case for RDRP resources.

In addition to enabling RDRP resource to use the standard generation model, which is the basis of the Proxy Demand Resource product, the ISO will introduce the Constrained Output Generation (COG) model, or similar functionality, as an option for RDRP resources that desire a discrete or "block" non-marginal dispatch. For purposes of this paper, the standard generation model will not be described here as that is well understood and is the model basis of the Proxy Demand Resource product. However, the COG model option is new and is described with additional detail below.

3.4.1 Constrained Output Generation Model

Certain RDRP resources, particular those that operate under a Firm Service Level construct are analogous to what the ISO terms COG units or Constrained Output Generation. The description of a COG unit is:

> *Constrained Output Generation (COG) units are those that are inflexible or "lumpy" in that they must operate at their full maximum output levels when they run. In addition, COG units generally have minimum run times such that, once they are started, they cannot be shut down until a pre-specified number of intervals has passed. While these units tend to be expensive to operate, they are often able to ramp up quickly and thus can fill an important gap in meeting peak demand, and can also quickly relieve shortages due to forced outages.15*

The ISO will incorporate the COG model, or similar functionality, into the RDRP design so that the ISO can more easily accommodate RDRP resources that require a discrete or "block" non-marginal dispatch.

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[15] See *Pricing Logic Under Flexible Modeling of Constrained Output Generating Units*, Pg. 3, found at: http://www.caiso.com/1fc2/1fc2f01961ca0.pdf

3.4.1.1 RDRP COG Option Design Parameters

3.4.1.1.1 Day-Ahead Market Participation

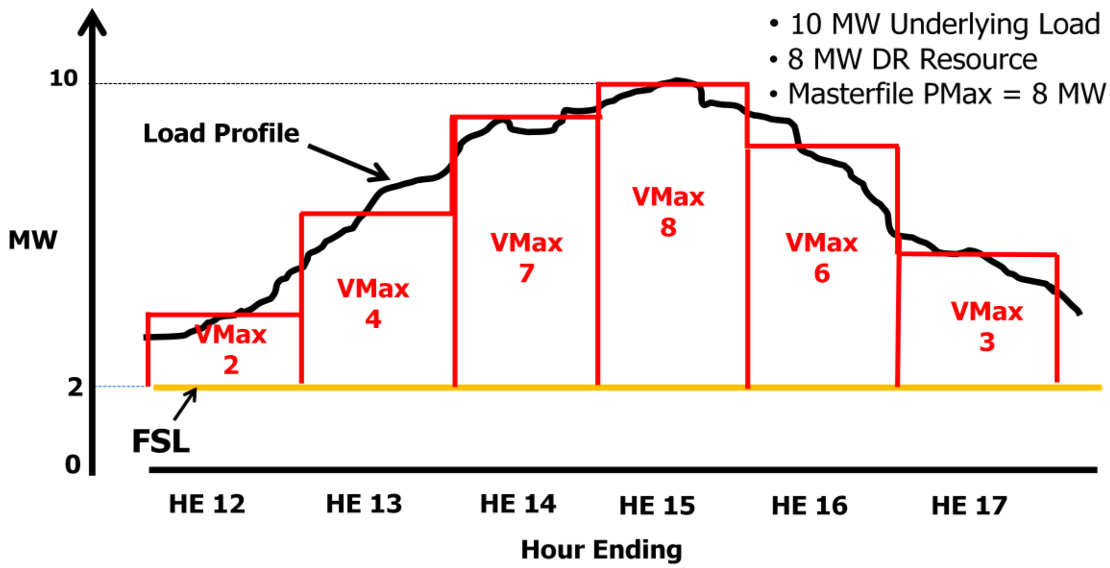
RDRP resources that elect the COG option will be treated as marginal resources in the day-ahead. Thus, a RDRP COG resource that is the marginal resource in the day-ahead energy market could clear a marginal megawatt quantity of energy. In other words, the ISO will not enforce a discrete or block megawatt clearing of energy in the day-ahead market for RDRP COG resources. Thus, all RDRP resources, including those electing the COG option, may submit multi-segment energy bids in the day-ahead market, like any other resource. However, the ISO will enforce the discrete or "non-marginal" dispatch for RDRP resource's that elect the COG option in the real-time, which, in the hour-ahead scheduling process, will require the scheduling coordinator to submit a single-segment energy bid.

3.4.1.1.2 Variable PMax (VMax) / PMin (VMin) in Real-Time

The COG model will have to be modified to accommodate RDRP resources. Unlike a simple-cycle combustion turbine, a RDRP resource does not have a fixed operating range; instead, the load of a RDRP resource is dynamic. Thus, this requires that the COG model have an hourly variable PMax/PMin capability or VMax/VMin, where the scheduling coordinator can bid a unique VMax value every hour through SIBR[16] in the real-time reflecting the RDRP resource's load curtailment capability relative to a Firm Service Level. To effectuate a discrete or "block" dispatch capability under the ISO's generation model, the VMin and VMax will be required to be within 0.01 MW of each other; thus, VMin = VMax -0.01 MW. Figure 2 below illustrates this concept.

[16] SIBR is the Scheduling Infrastructure Bidding Rules and is used by scheduling coordinators to accept bids and trades for energy and energy-related commodities, and receive feedback concerning submitted bids and trades.

Figure 2: Illustration of an 8 MW RDRP Resource with a 2 MW Firm Service Level and Potential Block Dispatches for HE 12-17 using a Variable PMax (VMax) Value



3.4.1.1.3 Resource Size Limit

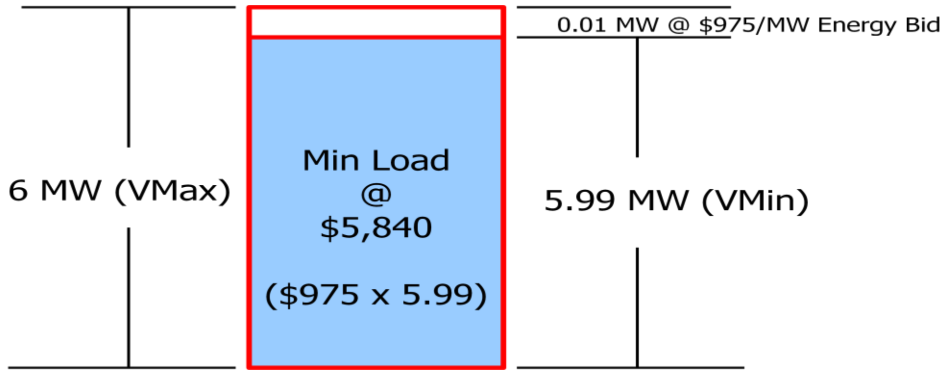
RDRP resources that elect the COG model option will be limited in size to a PMax of fifty (50) megawatts. This requirement is due to the fact that if a RDRP resource is the marginal resource and if, for example, the ISO only needs 20 MW of incremental energy, the COG model requires the ISO to take the full bid block amount, say 50 MW. Thus, to minimize this affect, the ISO desires to minimize the size of COG resources to minimize the impact of these potential, albeit infrequent, dispatch scenarios.

3.4.1.2 Calculated Hourly Minimum Load Costs

Under the RDRP COG option, a RDRP resource must submit a single segment bid for energy in the real-time through the hour-ahead scheduling process in the range of 95% Bid Cap ≤ Bid ≤ Bid Cap. The Start-Up Cost and Minimum Load Cost for RDRP COG resources will be set at $0 in the ISO master file. However, based on the hourly energy bid, the ISO system will calculate the RDRP COG resources minimum load cost for that hour by multiplying the energy bid by the RDRP's hourly VMin value. This will be called the Calculated Hourly Minimum Load Cost.

For example, given an hourly bid of $975/MW and a VMax of 6 MW and VMin of 5.99 MW, the Calculated Hourly Minimum Load Cost for that RDRP resource would be $975/MW x 5.99 MW = $5,840. The energy bid associated with the 0.01 MW, i.e. the difference between the VMax and VMin, would be priced at the energy bid of $975. Thus, the ISO's Real-Time Unit Commitment application would evaluate this RDRP resource for commitment based on a $5,840 Calculated Hourly Minimum Load Cost and a $975/MW energy bid. Figure 3 below illustrates the Calculated Hourly Minimum Load Cost.

Figure 3: Illustration of the Calculated Hourly Minimum Load Cost



3.4.1.3 Ability to Set Locational Marginal Price

If a RDRP COG resource is the marginal resource, its energy bid will be eligible to set the locational marginal price in the real-time market. However, a RDRP COG resource will not set the locational marginal price for the intervals where a RDP resource is constrained-on, per its minimum run time, and its energy is no longer required by the system, i.e. its energy bid is "out of the money" and, therefore, priced above the marginal resource. RDRP resources are eligible for bid cost recovery.

3.4.1.4 RDRP Resources the COG Option Election

The Demand Response Provider of a RDRP resource that elects the COG option must initially make that election within the timing requirements specified for ISO master file changes described in the applicable Business Practice Manual. A RDRP resource that elects the COG option will maintain its COG status for the full, applicable RDRP Term. RDRP COG resources will maintain their COG status indefinitely unless the scheduling coordinator for a RDRP resource elects to opt-out that RDRP resource from the COG option for the subsequent RDRP Term. Details and timing of the opt-out process will be detailed during the implementation phase of the RDRP.

3.4.1.5 RDRP COG Resources in the Real-Time Market

The ISO's Real-Time Dispatch application will dispatch a RDRP COG resource up to its VMax or down to zero (0) to ensure a feasible dispatch. The RDRP COG resource is eligible to set the real-time market locational marginal price in any dispatch interval, in which a portion of its output is needed to serve demand, not taking into consideration its minimum run time constraint. For the purpose of making this determination and setting the real-time market locational marginal price, the ISO will treat a RDRP COG resource as if it were flexible with an infinite ramp rate between zero (0) and its hourly VMax value, using the Calculated Hourly Minimum Load Cost and the submitted energy bid in the ISO's Real-Time Unit Commitment application. In circumstances in which the output of the RDRP COG resource is not needed as a flexible resource to serve demand, but the unit nonetheless is online as a result of a previous commitment or dispatch instruction by the ISO, the RDRP COG resource is eligible for bid cost recovery.

3.5 Market Impacts

3.5.1 Scarcity Pricing

The ISO's proposed scarcity pricing mechanism will apply when supply is insufficient to meet any of ISO's Ancillary Service (A/S) procurement requirements within an A/S region or sub-region. Any time any of these minimum A/S requirements are violated, i.e. there are insufficient reserves available, whether in the day-ahead market or real-time market, the ISO will activate the scarcity pricing mechanism, establishing a pre-determined high energy and A/S price in the A/S region or sub-region in which the reserve requirement-violation occurs to more accurately reflect the value of resources in such an emergency condition.

A design principle set forth in the settlement agreement is for RDRP to help mitigate, or limit the duration of, scarcity pricing. RDRP resources are available as early as the ISO issuing a Warning Notice and immediately prior to the ISO's need to canvas neighboring balancing authorities and other entities for available exceptional dispatch energy and/or capacity. Thus, given when RDRP resources are available, they will predominately help mitigate the duration of a scarcity pricing event should such an event be in effect when RDRP resources are activated. Thus, to clarify, calling RDRP resources does not trigger a scarcity pricing event, nor, conversely, does a scarcity pricing event trigger RDRP resources, but the introduction of a significant megawatt quantity of RDRP resources during a scarcity pricing event will very likely have a significant and mitigating impact on the prevailing system condition.

3.5.2 Residual Unit Commitment

The ISO commits resources in its day-ahead Residual Unit Commitment (RUC) process to ensure sufficient resources are available to meet the CAISO Forecast of CAISO Demand, i.e. to help prevent a supply shortage the following day. RDRP resources that can participate in the day-ahead market will not be eligible to participate in the RUC process due to the complexity associated with co-mingling the energy bid into the hour-ahead scheduling process associated with awarded RUC capacity and RDRP energy, and due to the different dispatch parameters (RUC vs. RDRP) for this energy in the real-time. Furthermore, RDRP resources that are configured to operate only in the Day-of timeframe and can only respond to a reliability event are neither suitable, nor eligible to be considered in the ISO's day-ahead RUC process.

3.5.3 Must Offer Obligation

RDRP resources that are designated as resource adequacy resources by the applicable Local Regulatory Authority will be considered resource adequacy qualifying (RA qualifying) resources for consideration under the ISO tariff and identified as such in the ISO masterfile. All RA qualifying RDRP resources will be deemed use-limited resources. As such, RDRP resources will not be required to apply for use-limited resource status as specified in ISO tariff section 40.6.4.1. Further, RA qualifying RDRP resources will have special designation like that of *Hydro and Non-Dispatchable Use-Limited Resources* as specified in ISO tariff section 40.6.4.3.2, but without an obligation to bid in the day-ahead market. During the ISO tariff development stage for the RDRP, the ISO will determine whether or not to weave RDRP resources into 40.6.4.3.2 or, if necessary, craft a new sub-section entirely.

3.5.3.1 Use Plans
The use plan obligation of RDRP resources as specified in ISO tariff section 40.6.4.2 will simply require a description of each registered RDRP resource, including its physical and contractual abilities and limitations by month during the RDRP Term. The form of this submission, either in hard or soft copy, e.g. potentially a template in the ISO's Demand Response System, will be delineated in detail during the RDRP implementation phase.

4 Design Considerations by Business Process

4.1 Qualification

4.1.1 Demand Response Provider
Before offering RDRP resources, a Demand Response Provider must be certified as a scheduling coordinator and enter into a Schedule Coordinator Metered Entity Agreement with the ISO or hire the services of an ISO certified scheduling coordinator that has an approved scheduling coordinator Metered Entity Agreement with the ISO.

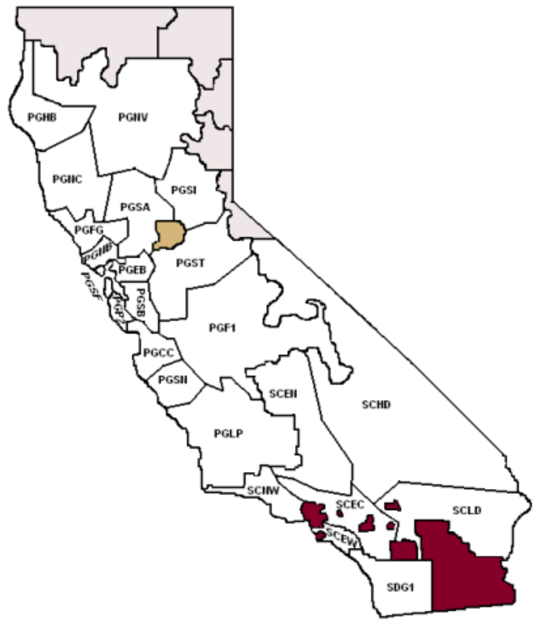
The Demand Response Provider must also establish agreements prior to participating in the ISO market, as applicable, including:

- Agreement with the load-serving entity
- Agreement with the utility distribution company
- RDRP Agreement with the ISO (to be established during the tariff development process)

4.1.2 RDRP Resources
RDRP resources must be able to reduce a measurable and verifiable quantity of load when dispatched by the ISO within a geographically specific location, i.e. a Sub-LAP.

4.1.2.1 Geographic Specificity
RDRP resources must be established within a ISO designated Sub-LAP; a RDRP resource cannot "straddle" two Sub-LAPs. A Sub-Lap is an ISO defined subset of PNodes within a Default LAP. There are twenty-three (23) Sub-LAPs that define the CAISO Controlled Grid. Figure 4 below is a graphical illustration of the Sub-LAP boundaries and Sub-LAP names within the ISO footprint.

Figure 4: Graphical Illustration of ISO Sub-LAPs



4.1.2.2 Minimum Load Curtailment

Minimum load curtailment is ≥ 500 kW per RDRP resource, albeit the ISO will consider smaller RDRP resources on an exception basis (ISO approval required); however, no RDRP resource will be less than 100 kW.

4.1.2.3 Minimum & Maximum Run Times

The minimum qualification requirement for a RDRP resource is to have a sustained response period or maximum run time of at least four (4) hours. A RDRP resource can register a longer sustained response period in the ISO masterfile, say six hours, as a RDRP resource's maximum run time. A RDRP resource can have a minimum run time of no greater than one (1) hour.

4.1.2.4 Availability Limits

RDRP Resources must be available for up to 15 Events and/or 48 hours per RDRP Term. The RDRP Term will be six (6) months with a summer and winter RDRP Term.

RDRP resources will automatically roll-over each RDRP Term; otherwise, the Demand Response Provider can opt-out their RDRP resource for a subsequent RDRP Term. With additional input from stakeholders, the timing and process for this election process will be detailed in the RDRP implementation phase.

4.1.2.5 Resource Size Limits

RDRP resources that elect the COG option will be limited in size to no greater than fifty (50) MW. Standard, non-COG RDRP resources have no ISO specified megawatt size limit.

4.1.2.6 Advance Notification and Ramp Period

RDRP resources must be capable of reaching their maximum curtailment capability (PMax) within 40-minutes of an ISO instruction. This 40-minute duration will impact the configuration of a RDRP resource's specified start-up time and ramp rate. For example:

- If Ramp Rate is ∞, then Advanced Notice (start-up time) can be ≤ 40 minutes
- If 20 MW (PMax) RDRP, then Ramp Rate can be 20MW/40Min or 0.5 MW/Min with 0 minutes Advance Notification Period (start-up time)
- If 20 MW (PMax) RDRP and Ramp Rate is 2 MW/min then it takes 10 minutes to reach full curtailment, thus this resource could have up to 30 minutes Advance Notification Period (start-up time)

4.1.2.7 Pre-Existing Meter Data

A RDRP resource must have sufficient pre-existing settlement quality meter data available to support the RDRP resource's Baseline Adjustment Window, e.g. 45 days.

4.2 Registration

4.2.1 Registration Overview

Demand Response Providers will follow the same processes and procedures for registering their underlying customers under RDRP resources as they do for Proxy Demand Resources. Once a RDRP resource has been established and assigned to a particular scheduling coordinator, the Demand Response Provider, with the necessary security credentials, can access the ISO's Demand Response System and begin to register service accounts under its respective RDRP resources. These underlying service accounts must be validated by the LSE and UDC to ensure the accuracy of the registered information and for the ISO to approve the registration to allow the RDRP resource to bid into the ISO market.

Detailed information about the ISO's Demand Response System can be found in the ISO's Demand Response System Users Guide found at: http://www.caiso.com/274c/274cef174c320.pdf

4.2.2 RDRP Resource Information

RDRP resources can be created from a single load or an aggregation of loads, assuming all RDRP resource qualifications are met. RDRP resources can elect the COG model option, if a discrete dispatch is desired. This COG election will be enabled through completion of a Resource Data Template and submission to the ISO for master file processing.

Like Proxy Demand Resource, the ISO will establish a number of default RDRP resources within each Sub-LAP. Custom aggregations, i.e. custom RDRP resources are also possible. Lead times for establishing a custom RDRP resource will be detailed in the RDRP implementation phase, but the process can be rather lengthy given a new generator resource needs to be established in the ISO's network model and entered into the ISO master file.

The ISO will also require a description of the RDRP resource being registered, including, but not limited to, a description of the underlying demand response program, availability limits of the demand response program, and any other limitations and/or requirements that may be important to the understanding and operation of a particular RDRP resource.

4.2.3 Resource Registrations

A RDRP resource is made up of multiple underlying registrations. A RDRP resource will be able to establish multiple active registrations under a single RDRP resource. Each registration could represent a different baseline methodology (where/when applicable) or demand response program type.[17]

During the registration process, the Demand Response Provider will enter/upload the underlying demand locations at the registration level into the ISO's Demand Response System including load-serving entity and utility distribution company information necessary for the RDRP resource's approval process.

The registrations under a RDRP resource must be within the same Sub-LAP and served by the same load-serving entity. All registrations will have an effective start and end date that must be validated by the load-serving entity and utility distribution company through the ISO's Demand Response System within 10-business days.

4.2.4 RDRP Term

Emergency demand response programs can be seasonal in nature, e.g. an air-conditioning cycling program. Other demand response programs can operate annually, e.g. large industrial/commercial interruptible load programs. The RDRP must be able to accommodate both types of demand response programs, including a proper accounting of availability limits, which must be tracked over a period of time. Thus the ISO has developed the concept of the RDRP Term.

The RDRP Term will run for six (6) months, with a summer and a winter term. The two RDRP Terms will run from:

- May to October- Summer
- November to April- Winter

Details as to the specific process and timing to make a RDRP Term election will be developed in the RDRP implementation phase; however, in principle, RDRP resources, by default, will be considered annual resources and will automatically roll-over from one RDRP Term to the next, without intervention needed by the scheduling coordinator or Demand Response Provider. RDRP resources that are seasonal will be registered as such, and will, effectively, opt-out from rolling over into a subsequent RDRP Term.

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[17] This functionality has been anticipated for implementation under the ISO's Proxy Demand Resource product. The RDRP will employ this functionality if it has not already been employed under Proxy Demand Resource.

Availability limits will be tracked over the RDRP Term. Each new RDRP Term resets the counter on RDRP resource availability limits.

4.3 Scheduling & Bidding

4.3.1 Bidding Requirements

A certified scheduling coordinator for a Demand Response Provider submits day-ahead energy bids into the ISO's day-ahead market and, at minimum, hourly energy bids for RDRP resources in the ISO's hour-ahead scheduling process through the ISO's Scheduling Infrastructure Business Rules system. A RDRP resource is modeled as a generator in ISO's network model and will follow the bidding rules and parameters of a generator.

Rules that will apply to RDRP resources are:

- Energy may not be self scheduled
- Multi-segment energy bid curves may be submitted for all RDRP resources in the day-ahead market
- Day-ahead energy bids will not be constrained to be in the range of the ISO bid cap and 95% of the bid cap as are energy bids in the real-time
- Single segment energy bids must be submitted in the real-time for RDRP COG resources; multi-segment bids may be submitted for all other RDRP resources in real time
- Real-time energy bids for all RDRP resources must be in the range of the ISO bid cap and 95% of the bid cap
- Minimum curtailment offer must be at least 500 kW (less on an exception basis)
- The ISO will apply a generator distribution factor to all aggregated RDRP resources; this will not be a biddable parameter

4.3.2 Limits on Start-Up Costs and Minimum Load Costs

All RDRP resources will have a PMin value of 0 MW and a $0 minimum load cost compensation value registered in the ISO masterfile. In addition, all RDRP resources will have a $0 start-up cost registered into the ISO master file.[18] Dispatch of RDRP resources in real-time will be based solely on the energy bids of RDRP resources between the ISO bid cap and 95% of the bid cap.

[18] A RDRP COG resource will have a Calculated Hourly Minimum Load Cost based on the energy Bid submitted into the hour-ahead scheduling process and may be required to have a non-zero value in the ISO master file to ensure proper validation in RTUC process, but the Calculated Minimum Load Cost will be calculated by the ISO based on the RDRP resource's hourly energy bid. Specific details will be evaluated in the RDRP implementation phase.

4.4 Notifications

4.4.1 Day-Ahead Market Clearing

A RDRP resource that offers energy in the day-ahead market will clear the day-ahead market as a marginal resource. In other words, a RDRP resource that elects the COG option will not clear the day-ahead market for a discrete or block quantity if it happens to be the marginal resource in the day-ahead market.

Day-ahead market results for RDRP resources will be published through the ISO's California ISO Market Results Interface (CMRI) system for review by the scheduling coordinator.

4.4.2 Real-Time Dispatch

RDRP resources are eligible for dispatch by the ISO for energy in the real-time only in the event of an imminent or actual system emergency as specified in ISO Operating Procedure E-508B or a transmission emergency. Once system conditions occur that enable the use of RDRP resources, the ISO operator will release the RDRP resources for commitment by the ISO's Real-Time Dispatch application.[19]

Once committed for dispatch, scheduling coordinators for the Demand Response Providers will receive financially-binding real-time dispatches through the ISO's Automated Dispatch System (ADS). This system will dispatch by resource and megawatt quantity, respecting any resource parameters and constraints as modeled in the ISO master file or as bid.

In the real-time, if a RDRP resource is the marginal resource, then a RDRP resource may receive a marginal dispatch for the marginal amount of energy actually needed by the ISO system. However, if a RDRP resource elects the COG model option, the resource will receive a discrete dispatch.

The ISO will update and maintain its emergency operating procedures and processes, including updates to its emergency operating procedure E-511- Interruptible Load Programs- to incorporate the RDRP. Notifications between the ISO and the Participating Transmission Owners will be as specified in this procedure.[20]

[19] Depending upon the nature of the emergency, the ISO's real-time dispatch application will evaluate the RDRP resources for commitment. The ISO's real-time dispatch (RTD) can operate in three modes: Real-Time Economic Dispatch (RTED), Real-Time Contingency Dispatch (RTCD), and Real-Time Manual Dispatch (RTMD). The ISO will use the RTED to optimally dispatch resources based on their bids and can be used to avoid an imminent System Emergency. The RTCD can be invoked in place of the RTED when a transmission or generation emergency occurs and there isn't sufficient time to wait for the next RTD run, which occurs every five (5) minutes starting at approximately 7.5 minutes prior to the start of the next dispatch interval.

[20] The current version of ISO Emergency Operating Procedure E-511can be found here: http://www.caiso.com/docs/2000/06/15/200006151111359621.pdf

4.4.3 Exceptional Dispatch

The ISO will endeavor to consistently dispatch RDRP resources through the ISO's market applications. However, all resources are subject to exceptional dispatch, including, for example, Proxy Demand Resources. Similarly, the ISO cannot exempt RDRP resources from these same tariff provisions. If system conditions are dire and a market application fails or does not commit a required RDRP resource that can resolve the reliability concern, the ISO cannot forego its ability to dispatch a RDRP resource under its exceptional dispatch authority and allow the situation to worsen. Thus, the ISO will preserve its exceptional dispatch capability with the expectation that this authority will be used judiciously and infrequently for RDRP resources.

4.4.4 Dispatch Timing

The ISO unit commitment and dispatch system will respect advance notification and ramp periods as specified for a particular RDRP resource and in compliance with the NAESB measurement and verification standard; however, no RDRP resource can have a combined advance notification and ramp period that exceeds forty (40) minutes. The advance notification and ramp period can be translated into an equivalent start-up time and ramp rate for a RDRP resource (see examples under section 4.1.2.6- Advance Notification and Ramp Period).

4.4.5 Tracking & Documenting Availability Limits

The ISO will track RDRP resource availability limits. If a RDRP resource receives a partial megawatt dispatch, say 30 MW against a 50 MW bid, for accounting purposes, the ISO will count the availability limit against the full RDRP resource.

Saying this, Demand Response Providers may be able to manage availability limits in a more refined manner given their individual customers and their ability to manage RDRP resource registrations. Therefore, the ISO will, as necessary, request a Demand Response Provider for the availability limits that they have recorded against a particular RDRP resource. If the Demand Response Provider's availability limits are greater than the ISOs, then the ISO will revise its availability limits against that RDRP resource accordingly, and document the change. Thus, for audit purposes, and to resolve any availability limit disputes between the ISO, Demand Response Provider or other party, Demand Response Providers, like the ISO, will be required to track availability limits by RDRP resource and make that information available to the ISO on-demand.

4.4.6 Outage Reporting

The scheduling coordinator for a RDRP resource will be required to interface with the ISO's outage reporting system. This outage reporting system is the tool that will be used to manage RDRP resource outages, to provide operator information about resource availability, and to exclude certain days from the baseline calculation, as allowed. The following circumstances are to be reported through the outage reporting system to exclude days from the baseline calculation:

- An unavailable RDRP resource for planned or forced outage reasons
  - A written explanation, via a text field in the outage reporting system, must accompany such a reporting

- A derated RDRP Resource
  - 50% abnormally low load relative to average load for that hour(s)
  - Must be non-weather or day-type related
  - A written explanation, via a text field in the outage reporting system, must accompany such a reporting
- Reported use for a Local Transmission system or Distribution system Emergency

The ISO's outage reporting system may also be used to report that a RDRP resource is not available after certain hours or is no longer available due to having reached its availability limits. For example, if an air-conditioning cycling program can only operate between noon and 8 PM and it is dispatched by the ISO at 6 PM, then the resource can only operate for the subsequent 2 hours, not the full 4 hours of a RDRP resource's availability. A notice to this effect should be submitted to the ISO's outage reporting system to indicate the resource is out of service starting at 8 PM. In addition, if a RDRP reaches its availability limits, then the RDRP resource should be listed as out of service for the duration of the RDRP Term.

4.5 Metering

4.5.1 Metering Overview

The ISO will establish a formal agreement between the ISO and the Demand Response Provider as the 'owner' of a RDRP resource. The ISO and the Demand Response Provider will enter into a RDRP agreement (to be developed as part of the ISO tariff development process). To schedule, bid and settle RDRP resources, the Demand Response Provider may perform these duties as a registered certified scheduling coordinator with the ISO, or the Demand Response Provider may contract for these services through an ISO certified scheduling coordinator. The ISO expects the scheduling coordinator representing the scheduling coordinator Metered Entities (i.e. the RDRP resources) to aggregate the settlement quality meter data for each registration associated with a RDRP resource and submit this settlement quality meter data to the ISO at T+5B noon 1) daily for RDRP resources that offer day-ahead energy and 2) only after an event has occurred for RDRP resources that offer energy only in the real-time. Each RDRP resource may have multiple registrations. A RDRP resource may represent an aggregate of settlement quality meter data for one or more loads within an Aggregate Pricing Node (APNode), where an APNode is constrained geographically within a Sub-LAP. A RDRP resource can be a single load and single registration settled at a single Pricing Node (PNode) within a Sub-LAP or multiple loads and multiple registrations settled at an APNode based on the weighted-average of a collection of PNodes that make up APNode within a Sub-LAP. Either way, settlement quality meter data must be aggregated from all of the underlying loads per each registration that make up a RDRP resource. The ISO's expectation is that the aggregate settlement quality meter data of any registration can be disaggregated down to the underlying loads, for audit and inspection purposes by the ISO, or by the ISO's authorized inspector, where and when necessary, subject to Local Regulatory Authority requirements.[21] In addition, scheduling coordinators for Scheduling Coordinator Metered Entities, i.e. RDRP resources, must conduct scheduling coordinator self-audits annually as further described in the Business Process Manual for Metering and in ISO tariff section 10.3.10.

4.5.2 Meter Service Agreement for Scheduling Coordinators

A scheduling coordinator for a Scheduling Coordinator Metered Entity must sign a Meter Service Agreement for Scheduling Coordinators with the ISO. The scheduling coordinator for a Scheduling Coordinator Metered Entity is responsible for providing settlement quality meter data for Scheduling Coordinator Metered Entities it represents. Such agreements specify that the scheduling coordinator require their Scheduling Coordinator Metered Entities to adhere to the applicable meter requirements of the ISO tariff, which include those set forth in section 6 of the Business Practice Manual for Metering. A pro forma version of the Meter Service Agreement for Scheduling Coordinators is set forth in Appendix B.7 of the ISO tariff.

4.5.3 Metering Process

RDRP resources will be represented as Scheduling Coordinator Metered Entities. A scheduling coordinator for a Scheduling Coordinator Metered Entity will aggregate settlement quality meter data by registration for its RDRP resources by noon T+5B days as follows. For RDRP resources that offer:

- Day-ahead energy (in addition to real-time energy):
  - Settlement quality meter data is required to be submitted daily
- Real-time energy only:
  - Settlement quality meter data is required only after an event has occurred

Settlement quality meter data must be submitted into the ISO's Demand Response System in an XML data format, along with the relevant Baseline Adjustment Window data to support the baseline calculation either via an Application Programming Interface or a User Interface. The ISO will use the settlement quality meter data in conjunction with a baseline to determine the financial settlement between the ISO and the scheduling coordinator for the RDRP resource.

4.5.4 Meter Data Intervals

RDRP resource will be dispatched in the ISO's real-time market. As such, RDRP resources will be dispatched and settled on a 5-minute time scale. If a Local Regulatory Authority does not require interval metering less than 15-minutes, the ISO will accept 15-minute recorded meter data intervals provided the responsible scheduling coordinator parses the 15-minute recorded settlement quality meter data into three 5-minute intervals for submission to the ISO's Demand Response System.

4.5.5 Meter Data Submission & Format

Meter data submittal is due, along with the supporting Baseline Adjustment Window data, only after an event has occurred for RDRP resources that only offer energy in the

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[21] Additional Information about audit and testing by the ISO can be found in ISO tariff section 10.3.10.2 and in the Business Process Manual for Metering.

real-time; otherwise, daily submission is required for RDRP resources that offer day-ahead energy. Settlement quality meter data must be submitted to the ISO's Demand Response System in a XML format by noon at T+5B days.

- Five (5) minutes interval for twenty-four hours of the event day
- Meter data submittals must include all twenty-four hours for any given event day. Partial, incomplete, or gaps in data will result in the inability of the Demand Response System to calculate a baseline and associated energy delivery.
- Five minute Meter Data can be created by parsing 15-minute recorded Meter Data into three 5-minute intervals.
- Meter data must be uploaded for each registration that makes up a RDRP resource
- All data must be submitted in XML format[22]

The actual XML formatted meter data submission file must contain the following:

- RDRP resource ID
- Registration ID
- Submission in Kilowatt Hours (kWh)
- Measurement type set to LOAD
- Submitted in Greenwich Mean Time (GMT)
- Time interval of 5- minutes

4.5.6 Distribution Loss Factors

When a RDRP resource is connected to a utility distribution company's distribution system, the responsible scheduling coordinator must submit adjusted interval settlement quality meter data by an estimated distribution system loss factor to derive an equivalent ISO Controlled Grid level measure. Such estimated distribution system loss factors must be approved by the relevant Local Regulatory Authority prior to a RDRP resource's deployment.

4.5.7 Meter Data Audit

The ISO's authority to audit on-demand a scheduling coordinator's settlement quality meter data down to the individual service account level and/or sampling data and associated algorithms, as applicable. This right is important to support the provision of 'trust but verify' given the ISO has no formal agreement with the end-use customers that are ultimately providing the reliability energy service to the ISO. The ISO would expect to infrequently rely upon its audit authority; however, audits, if and when necessary, will be an important enforcement tool to ensure credibility and trust in the RDRP.

4.5.8 Meter Certification

Scheduling coordinators for Scheduling Coordinator Metered Entities must ensure the metered entities they represent have certified meters or must follow the certification

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[22] The technical requirements for Meter Data submission in XML format may be found on the ISO website at the following location: www.caiso.com > Initiatives & Meetings > Current Initiatives > Demand Response > Sub Initiatives > Proxy Demand Resources (PDR) > Technical Requirements > PDR Meter Data XSD.zip

process for ISO Metered Entities. See Business Process Manual for Metering for additional detail and information.

4.5.9 Local Regulatory Agency Certification Requirements

Scheduling coordinators representing Scheduling Coordinator Metered Entities must ensure the meters for their RDRP resources are certified in accordance with the certification requirements of the appropriate Local Regulatory Authority. Scheduling coordinators are responsible for obtaining any necessary approval of the relevant Local Regulatory Authority to its proposed security and validation, estimation, and editing procedures. The ISO does not perform any validation, estimation and/or editing procedures on the settlement quality meter data it receives from scheduling coordinators for Scheduling Coordinator Metered Entities.

5 Performance & Compliance

5.1 Testing

The ISO can issue one (1) unannounced test dispatch per year to a RDRP resource to ensure the availability and performance of that resource. The Demand Response Provider can also schedule additional RDRP test events in coordination with the ISO.

The ISO's preference will be to rely on actual events to determine the availability and performance of RDRP resources to avoid the burden of a test event on end-use customers; however, if no events have been called within the year, then the expectation is one test event will be performed annually, toward the end of a RDRP Term, to determine RDRP resource availability and performance.

If a test event is necessary, the ISO will generally perform a test event in the summer (May – October) RDRP Term, corresponding to the traditional months when loads are higher. If a RDRP resource is configured such that it is only available in the winter (November – April) RDRP Term, then the ISO will test that resource in that RDRP Term.

Test events will count toward the RDRP availability limit of 15 events and/or 48 hours per RDRP Term. The ISO will share test event results with the RDRP resource's applicable Local Regulatory Authority.

5.2 RDRP Availability Standards

Availability standards for demand response resources that participate in the wholesale market, including RDRP resources, will be developed through the ISO's Standard Capacity Product (SCP) initiative.[23]

[23] The purpose of the SCP initiative is to define and formalize a Standard RA Capacity Product which is intended to simplify and increase the efficiency of the RA program.

Effective January 1, 2010, the ISO implemented the RA Standard Capacity Product as approved by FERC order dated June 26, 2009 (ER09-1064-000).[24] FERC approved the SCP on the grounds that it will: (1) enable market participants to efficiently and flexibly buy, sell, and trade RA capacity without the burden of negotiating the availability requirements of each transaction; and (2) establish uniform metrics and provide market participants with a readily-available means to satisfy their RA requirements, which will enhance reliability.

In the June 26 Order, FERC accepted in part and rejected in part the ISO tariff amendments to implement SCP. In that order, FERC granted temporary exemptions from the SCP availability charges and payments for:

1. Resources whose qualifying capacity value is determined by the CPUC or a Local Regulatory Authority using historical output that has not been adjusted to correct for the possible double-counting of outages (this includes wind, solar, non-dispatchable cogeneration, non-dispatchable biomass and non-dispatchable geothermal facilities); and
2. Demand response.

FERC directed "the CAISO to work with stakeholders, the CPUC, and local regulatory authorities to determine when the proposed exemptions should ultimately sunset, and the CAISO and stakeholders should diligently work toward a sunset in a timely manner." On June 22, 2010 the ISO filed tariff language proposing to end the exemption for the resources listed under item #1. The next SCP market design effort will address demand response including RDRP.

5.3 Missing or Unreported Meter Data

If by T+5B noon after an event, the scheduling coordinator for the Demand Response Provider has not reported settlement quality meter data by registration for a RDRP resource to the ISO, including the supplemental meter data to support the Baseline Adjustment Window, the ISO will be unable to calculate the performance of the RDRP resource. This includes the scenario where even if meter data is missing for one of the registrations under a RDRP resource that has multiple registrations, the ISO will be unable to calculate the actual performance of the RDRP resource, resulting no "meter data" and, therefore, uninstructed energy settlement charges. In other words, the ISO would not be able to accurately settle with the scheduling coordinator, Demand Response Provider, or load-serving entity.

[24] The FERC order is located on the CAISO website at: http://www.caiso.com/23d9/23d9c3c11970.pdf

6 Settlements

6.1 Overview

RDRP resources will be settled through the ISO market like Proxy Demand Resources, employing NAESB methodologies Baseline Type I- where interval meter data exists, or Baseline Type II- where interval meter does not exist. And like Proxy Demand Resource, where the load-serving entity and Demand Response Provider can be separate entities, the RDRP will employ the Default Load Adjustment mechanism. This settlement mechanism adds back the actual performance of the RDRP resource to the meter quantity of the respective load-serving entity in the ISO's Uninstructed Imbalance Energy pre-calculation, resulting in an "adjusted" metered demand value.

6.2 Baselines

6.2.1 Baseline Types

For the RDRP a baseline will be used to determine a RDRP resource’s performance. More specifically, metered load during the event hour(s) is compared against a baseline, a statistical estimate of how much electricity would have been used during the same time period. The difference between metered load and the baseline is the basis for payment.

The RDRP will rely on two of the NAESB measurement and verification standard baseline types, specifically:

- Baseline Type – I
  A Baseline performance evaluation methodology based on a Demand Resource’s historical interval meter data which may also include other variables such as weather and calendar data

- Baseline Type – II
  A Baseline performance evaluation methodology that uses statistical sampling to estimate the electricity consumption of an Aggregated Demand Resource where interval metering is not available on the entire population

The only distinction between Baselines Type I and Type II will be the method for gathering the underlying load data. In the case of Baseline Type I, the scheduling coordinator will submit settlement quality meter data that was sourced from the physical, interval meters installed on the premise of the underlying service accounts for each of the active registrations under a particular RDRP resource. For Baseline Type II, the settlement quality meter data submitted to the ISO will be derived from credible sources other than a physical, interval meter such as from sampled data, SCADA data or other method that can substantiate the performance of the population of underlying service accounts for the active registrations under a particular RDRP resource.

For Baselines Type I and Type II, the ISO will apply the same baseline calculation methodology for determining a RDRP resource’s performance for settlement purposes, at the registration level. For RDRP resources, like Proxy Demand Resources, the ISO will employ the "10 in 10" baseline calculation methodology.

6.2.2 Baseline Type II- Proxy Meter Data

The distinction between Baseline Type I and Type II is how the underlying load of the RDRP resource is measured so that the "actual" usage/demand of the RDRP resource can be derived. For Baseline Type I, the actual demand of the RDRP resource is based on interval meter data that is no more granular than 15-minutes. However, resources that rely on the Baseline Type II do not have a meter that is recording actual demand through an interval meter, e.g. air-conditioning cycling or other direct load control program. Thus, Baseline Type II resources must derive actual demand using sampling and statistics via data loggers or other credible devices, SCADA data, or other means that can be substantiated as accurate and reasonable for the derivation of a Proxy Meter Data value.

Further research is being conducted in this area, with the best and most economical approaches for deriving Proxy Meter Data still under investigation. At this juncture, the ISO's approach will be for a Demand Response Provider to submit its methodology for deriving Proxy Meter Data to the ISO for review. Any method proposed by a Demand Response Provider must be fully auditable by the ISO. As to the review process, the ISO will take 10-business days to review, comment and seek clarification from the Demand Response Provider on its proposed Proxy Meter Data methodology.

Any proposed Proxy Meter Data methodology should be in conformance, as applicable, with the NAESB Phase I and Phase II measurement and verification standards. The Phase II standard is currently under development, but may be finalized prior to RDRP's release in 2012. Below is an excerpt on statistical sampling from the *Draft NAESB Phase II Measurement and Verification Standard*:[25]

> **Statistical Sampling**
> The method of statistical sampling used should conform to an accepted methodology and should be specified in the governing documents. The following list provides examples of currently accepted methodologies:
>
> - The Association of Edison Illuminating Companies (AEIC) Load Research Manual
>   - Chapter 4 – Sample Design and Selection
>   - Chapter 5 – Sample Implementation[26]
> - The Federal Energy Management Program M&V Guidelines: Measurement and Verification for Federal Energy Projects – Appendix B27;

[25] NAESB Draft Retail Phase 2 M&V Standards for DR Programs found here: http://naesb.org/pdf4/dsmee_group2_070910w1.doc.
[26] Association of Edison Illuminating Companies (AEIC), Load Research Manual,2nd ed., Birmingham, AL, 2001, www.aeic.org
[27] U.S. Department of Energy. M&V Guidelines: Measurement and Verification for Federal Energy Management Projects Version 3.0. 2008. (or current version).

- The California Energy Efficiency Evaluation Protocols[28];
- The California Evaluation Framework – Chapter 13[29]; or
- The Independent System Operator (ISO)-New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources, Section 7[30].

The general steps to be taken in statistical sampling are, but are not limited to:

- Define the population
- Design the sample to meet program objectives.
- Specify the listing of units available to be sampled which is sometimes called the sampling frame
- Identify design (auxiliary) variables
    - Choose the sampling technique
    - Choose stratification variable(s)
    - Select allocation procedure
    - Estimate means and variances of loads
    - Examine sample size requirements
    - Select sampling techniques and design
- Determine the sample size
- Identify those units to be in the sample
- Identify the criteria for selecting those units to be substituted for sample units who decline
    - Select sample and alternates
    - Validate sample
    - Contacting and enroll the customers to be in the sample, and install the metering devices, if needed
    - Collect interval meter data.

The sample drawn should comport to a level of statistical significance that supports the goals of the program

6.2.3 Other Baseline Types

The ISO is willing to consider stakeholder proposals for other baseline methods under Baseline Type I and Type II. However, stakeholders that desire the ISO to employ other baseline methodologies, now or in the future, should provide the ISO written documentation and supporting evidence, including the types of customers for which the baseline methodology would apply for consideration by the ISO, its stakeholders, and FERC. The ISO will be required to incorporate any new baseline methodologies into its

[28] California Public Utilities Commission, California Energy Efficiency Evaluation Protocols: Technical, Methodological, and Reporting Requirements for Evaluation Professionals, 2006. (http://www.cpuc.ca.gov/PUC/)

[29] California Public Utilities Commission, The California Evaluation Framework, current version. (http://www.cpuc.ca.gov/PUC/).

[30] ISO-New England, Manual for Measurement and Verification of Demand Resources, (M-MVDR), current version. (http://www.iso-ne.com/rules_proceds/isone_mnls/index.html).

tariff, which will require a rigorous process, including stakeholder review/input, a tariff amendment and, ultimately, FERC approval.

6.2.4 Baseline Methodology

RDRP will employ the "10 in 10" baseline methodology, such that when an event occurs, the ISO's Demand Response System will select the most recent, ten (10) similar (weekdays vs. weekends/holidays) non-event days; the ISO will not eliminate abnormally low or abnormally high usage days. A Load Point Adjustment or "Morning-of Adjustment Factor" will be used to adjust the load, up or down, by no more than 20% (floor at 80% and ceiling of 120%). The Baseline Adjustment Window will be forty-five (45) days. If there are not enough similar days to meet the minimum ten (10) days basis, then the baseline will be calculated using the highest usage prior event days within the Baseline Adjustment Window to reach the minimum number of days. If there are not enough target days, i.e. ten (10) days, to establish the baseline, then the baseline is calculated using the selected minimum number of days that are available. Finally, interval meter data- Type I, or Proxy meter data- Type II, which is submitted by the scheduling coordinator into the Demand Response System as 5-minute interval data will be converted to hourly data for the purpose of calculating the raw baseline data. Raw baseline data is calculated at the Registration level.

6.2.5 Events Considered in the Baseline Calculation

For RDRP resources, Events are defined as anything that would significantly alter the normal performance output of a RDRP resource.[31] The following Events will be considered as "Event Days" by the ISO for determining a RDRP resource's performance and settlement in the ISO's baseline calculations:

- ISO real-time dispatch
- Demand Response Provider use for a Local Transmission system & Distribution system Emergency
- Forced or planned outages
    - An unavailable RDRP resource for planned or forced outage reasons
        - A written explanation, via a text field in the ISO's outage reporting system, must accompany such a reporting
    - A derated RDRP resource
        - 50% abnormally low load relative to average load for that hour(s)
        - Must be non-weather or day-type related
        - A written explanation, via a text field in the ISO's outage reporting system, must accompany such a reporting

6.2.6 Outage Reporting Impacts on Baseline Calculation

Following are examples demonstrating how specific outages will impact a RDRP resource's performance via the baseline calculation.

[31] Only ISO real-time dispatches and Local Transmission & Distribution Emergency Events will count against the availability limits of a RDRP resource. For instance, forced outages of a RDRP resource is considered an Event when calculating RDRP resource performance in a baseline calculation; however, a forced outage is not an "Event" that counts against a RDRP resource's availability limits.

Scenario:

> An outage was entered into the ISO's outage reporting system for a RDRP resource as unavailable on Trade Date 6/1/2010 for HE 1-8.

Example 1:

> On 6/2/2010, there is an event for HE 13. When calculating the baseline for the 6/2 event, the 6/1 trade date will be excluded due to the outage (same day type).

Example 2:

> On 6/1/2010, there is an event for HE 14. When calculating the baseline for 6/1 event, the previous weekday trade dates would be evaluated for inclusion. RDRP Performance for 6/1 – HE 14 would be calculated by the ISO Demand Response System even though there was an outage on the RDRP resource in the morning.

6.3 Settlement Details

6.3.1 Load Point Adjustment

A RDRP Event triggers the Load Point Adjustment (morning-of adjustment) calculation. The calculation uses the three (3) prior hours, excluding the hour immediately prior to the Event start. The Load Point Adjustment adjusts the raw baseline values using a 20% adjustment factor, with a floor of 80% and a ceiling of 120%.

6.3.2 Default Load Adjustment

The Default Load Adjustment mechanism adds back the actual performance of the RDRP resource to the meter quantity of the respective load-serving entity in the ISO's Uninstructed Imbalance Energy pre-calculation, resulting in an "adjusted" metered demand value, called the Adjusted Meter Quantity, by Default LAP. More specifically:

- The Default Load Adjustment is the amount of load curtailed by RDRP resources within a Default LAP for a specific load-serving entity.
- The Default Load Adjustment is derived by aggregating the performance of each RDRP resource, by load-serving entity and by Sub-LAP, within a Default LAP.

6.3.3 Real-Time Energy Settlement

6.3.3.1 Instructed Imbalance Energy (IIE)

Instructed Imbalance Energy (IIE) is settled under Charge Code 6470. Charge Code 6470 is the product of the IIE megawatt quantity multiplied by the real-time locational marginal price. There is no change required to Charge Code 6470 calculation since RDRP resources are considered as a supply resource, like other generators, under this charge code.

6.3.3.2 Uninstructed Imbalance Energy (UIE)

Uninstructed Imbalance Energy (UIE) is settled under Charge Code 6475. Charge Code 6475 is the product of the UIE megawatt quantity multiplied by the real-time locational marginal price. The calculation for UIE was previously altered by the Proxy Demand Resource implementation to employ the Default Load Adjustment to a load-serving entity's metered demand, which results in an Adjusted Meter Quantity settled in Charge Code 6475. This same change and implementation applies to RDRP resources.

6.3.4 Settlement Charge Code Impacts

6.3.4.1 Load-Serving Entity Settlement Impacts

Like Proxy Demand Resource, under RDRP, a Default Load Adjustment value will be added to the load-serving entity's submitted metered demand which results in the load-serving entity having an Adjusted Meter Quantity.

All deviation based charges use the Adjusted Meter Quantity that is included in the UIE pre-calculation; therefore, there are no explicit updates required to the Settlement Charge Code Configuration Guide, although though the following Charge Codes shown in Table 1 are impacted by this Adjusted Meter Quantity pre-calculation adjustment:

Table 1: Load-Serving Entity Settlement Impacts

Charge Code Number	Charge Code Name	Billable Quantity
721	Intermittent Resources Net Deviation Allocation	Net Negative Uninstructed Deviations
752	Monthly Participating Intermittent Resources Export Energy A	Net Negative Uninstructed Deviations
1407	MSS Positive Deviation Penalty	Positive Deviation Qty
1487	Emergency Energy Exchange Program Neutrality Adjustment	Net negative uninstructed Energy
2407	MSS Negative Deviation Penalty	Negative Deviation Qty
4506	Energy Transmission Services - Net Uninstructed Deviations	Absolute value of Net Uninstructed Deviations
4536	Market Usage - Uninstructed Energy	absolute value of each Scheduling Coordinator's Net uninstructed deviations by Settlement Interval. The Billing Determinant for Market Usage Uninstructed Energy will be the absolute value of net portfolio deviations by Settlement Interval.
6475	Real Time Uninstructed Imbalance Energy Settlement	Stlmt Int RT UIE1 + RT UIE2
6486	Real Time Excess Cost for Instructed Energy Allocation	Min (0, UnitRealTimeUIE + AvailableUndispatchedBidQuantity)
6678	Real Time Bid Cost Recovery Allocation	Proportional to BA's Measured Demand Net Negative UIE for load following MSS.
6806	Day Ahead Residual Unit Commitment (RUC) Tier 1 Allocation	Net Negative Demand Deviations

6.3.4.2 Demand Response Provider Settlement Impacts

The Proxy Demand Resource product required changes to the pre-calculations of certain charge codes. RDRP resources rely on these same pre-calculation changes, but for a subset of charge codes given RDRP resources, unlike Proxy Demand Resources, are limited to providing only energy services into the ISO's real-time market.

Table 2 below lists the charge codes that will be applicable to Demand Response Providers who operate RDRP resources.

Table 2: Demand Response Provider Impacted Charge Codes

Charge Code Number	MRTU Charge Code Name	Billable Quantity
721	Intermittent Resources Net Deviation Allocation	Net Negative Uninstructed Deviations
752	Monthly Participating Intermittent Resources Export Energy Allocation	Net Negative Uninstructed Deviations
1487	Emergency Energy Exchange Program Neutrality Adjustment	Net negative uninstructed Energy
2999	Default Invoice Interest Payment	Scheduling coordinator's share of total unpaid creditors for the Bill Period
3999	Default Invoice Interest Charge	Default Invoice Interest
4506	Energy Transmission Services - Net Uninstructed Deviations	Absolute value of Net Uninstructed Deviations
4535	Market Usage – Instructed Energy	Absolute value of scheduling coordinator's of Instructed Imbalance Energy by resource. The total Instructed Imbalance Energy quantity (MWh) is the sum of Standard Ramping Energy, Optimal Energy, Real-Time Minimum Load Energy, Regulation Energy, Ramping Energy Deviations, Derate Energy, Real-Time Self-Schedule Energy, Residual Imbalance Energy, and Operational Adjustments for the Day-Ahead and Real-Time.
4536	Market Usage – Uninstructed Energy	Absolute value of each scheduling coordinator's Net uninstructed deviations by Settlement Interval. The Billing Determinant for Market Usage Uninstructed energy will be the absolute value of net portfolio deviations by Settlement Interval.
4575	SMCR Settlements, Metering, and Client Relations	Assessed if there is any settlement charge activity within the month
5999	FERC Mandated Interest on Re-Runs	Net Amount of the original Invoice and the Re-run Invoice
6470	Real Time Instructed Imbalance Energy Settlement	IIE QTY
6475	Real Time Uninstructed Imbalance Energy Settlement	Stlmt Int RT UIE1 + RT UIE2
6486	Real Time Excess Cost for Instructed Energy Allocation	Min (0, UnitRealTimeUIE + AvailableUndispatchedBidQuantity)
6620	Bid Cost Recovery Settlement	Max (0, Sum of IFM Net Amt + Sum of RUC Net Amt + Sum of RTM Net Amt)*(-1)

7 Stakeholder Initiative Process

7.1 Milestones

Figure 5 below specifies the six key upcoming milestones and their associated deliverable dates for the RDRP stakeholder initiative.

Figure 5: RDRP Stakeholder Initiative Milestones

7.2 Schedule

To achieve the above milestones, Table 3 below outlines a more detailed schedule between posting of the RDRP Straw Proposal and reaching the implementation of the RDRP.

Table 3: RDRP Stakeholder Initiative Detailed Schedule

Planned Date	Item
Jul 12, 2010	• Post Straw Proposal • Publish Stakeholder Meeting Agenda & Market Notice
Jul 15, 2010	Post Market Notice for Stakeholder Meeting
Aug 3, 2010	Post Stakeholder Meeting Presentations
Aug 5, 2010	Stakeholder Meeting to Review Straw Proposal

Planned Date	Item
Aug 12, 2010	Comments due on Straw Proposal
Aug 17, 2010	Working Group Conference Call
Sep 1, 2010	Post Draft Final Proposal
Sep 6, 2010	Holiday- Labor Day
Sep 13, 2010	Stakeholder Conference Call to Review Final Draft Proposal
Sep 20, 2010	Comments due on Draft Final Proposal
Sep 23, 2010	Clarified Draft Final Proposal Posted
Sep 29, 2010	Comments due on Clarified Draft Final Proposal
Nov 1-2, 2010	CAISO Board Approval of RDRP
Nov 25-26, 2010	Thanksgiving Holiday
Mar 2011	Proposed Draft Tariff Language Posted
May 2011	Final Tariff Language Filed at FERC
July 2011	FERC Final Order Issued Approving RDRP

Attachment 1: Terms & Definitions

Terms & Definitions:

TERM	DESCRIPTION
Advance Notification	One or more communications to Demand Resources of an impending Demand Response Event in advance of the actual event. (NAESB)
Aggregated Pricing Node (APNode)	A Load Aggregation Point, Trading Hub or any group of Pricing Nodes as defined by the CAISO. (CAISO Tariff)
Automated Dispatch System (ADS)	The CAISO systems application to communicte dispatch Instructions to scheduling coordinators. (CAISO Tariff)
Baseline	A Baseline is an estimate of the electricity that would have been consumed by a Demand Resource in the absence of a Demand Response Event. The Baseline is compared to the actual metered electricity consumption during the Demand Response Event to determine the Demand Reduction Value. Depending on the type of Demand Response product or service, Baseline calculations may be performed in real-time or after-the-fact. (NAESB)
Baseline Adjustment	An adjustment that modifies the Baseline to reflect actual conditions immediately prior to or during a Demand Response Event to provide a better estimate of the Energy the Demand Resource would have consumed but for the Demand Response Event. The adjustments may include but are not limited to weather conditions, near real time event facility Load, current Demand Resource operational information, or other parameters based on the System Operator's requirements. (NAESB)
Baseline Adjustment Window	The period of time prior to a Demand Response Event used for calculating a Baseline adjustment. (NAESB)
Baseline Type I (Interval Meter)	A Baseline performance evaluation methodology based on a Demand Resource's historical interval meter data which may also include other variables such as weather and calendar data. (NAESB)
Baseline Type II (Non-Interval Meter)	A Baseline performance evaluation methodology that uses statistical sampling to estimate the electricity consumption of an Aggregated Demand Resource where interval metering is not available on the entire population. (NAESB)
Bid Costs	The costs for resources manifested in the Bid components submitted, which include the start-up Cost, minimum load cost, and energy bid cost. For RDRP resources, start-up cost and minimum load cost is $0.
Bid Cost Recovery	The CAISO settlements process through which Eligible Resources recover their Bid Costs. (CAISO Tariff)
CAISO Controlled Grid	The system of transmission lines and associated facilities of the Participating Transmission Owners that have been placed under the CAISO's Operational Control. (CAISO Tariff)
Calculated Hourly Minimum Load Cost	The hourly Minimum Load Cost that is calculated based on a RDRP COG resource's VMax and the energy bid submitted into the hour-ahead scheduling process. The Calculated Hourly Minimum Load Cost is calculated by multiplying the energy bid by the VMax MW value.
Day-Ahead Market	A series of processes conducted in the day-ahead that includes the Market Power Mitigation-Reliability Requirement Determination, the Integrated Forward Market and the Residual

TERM	DESCRIPTION
	Unit Commitment. (CAISO Tariff)
Default Load Adjustment	A settlement mechanism that adds back the actual performance of the RDRP resource to the meter quantity of the respective load-serving entity in the ISO's Uninstructed Imbalance Energy pre-calculation, resulting in an "adjusted" metered demand value.
Demand Response Event (Event)	The time periods, deadlines and transitions during which Demand Resources perform. The System Operator shall specify the duration and applicability of a Demand Response Event. All deadlines, time periods and transitions may not be applicable to all Demand Response products or services. (NAESB)
Demand Response Provider (DRP)	An entity that is responsible for delivering Demand Response Services from a RDRP resource providing Demand Response Services, which has undertaken in writing by execution of the applicable agreement to comply with all applicable provisions of the CAISO Tariff
Deployment	The time at which a Demand Resource begins reducing Demand on the system in response to an instruction. (NAESB)
Dispatch Interval	The 5-minute interval over which the real-time dispatch measures deviations in generation and demand and selects ancillary services and supplemental energy resources to provide balancing energy in response to such deviations. (CAISO Tariff)
Energy Service	A type of Demand Response service in which Demand Resources are compensated based solely on Demand reduction performance during a Demand Response event. (NAESB)
Expected Energy	The total Energy that is expected to be curtailed by a RDRP resource, based on the dispatch of that resource, as calculated by the real-time market (RTM), and as finally modified by any applicable Dispatch Operating Point corrections. The calculation is based on the Dispatch Operating Point trajectory for the three-hour period around the target Trading Hour (including the previous and following hours), the applicable real-time locational marginal price for each dispatch interval of the target Trading Hour. Expected Energy is used as the basis for Settlements and for calculating the Performance Incentive of a RDRP resource. (CAISO Tariff)
Firm Service Level (FSL)	A performance evaluation methodology based solely on a demand Resource's ability to reduce to a specified level of electricity demand, regardless of its electricity consumption at deployment. This concept is referred to as a Maximum Base Load in the NAESB M&V standard.
Generation Distribution Factor (GDF)	A factor the CAISO will apply to proportion the bid of the RDRP resources among the nodes that make up the APNode.
Hour-Ahead Scheduling Process (HASP)	The process conducted by the CAISO beginning at seventy-five minutes prior to the Trading Hour through which the CAISO conducts the following activities: 1) accepts Bids for Supply or Energy, including imports and exports and Ancillary Services imports to be supplied during the next Trading Hour that apply to the MPM-RRD, RTUC, STUC, and RTD; 2) conducts the MPM-RRD on the Bids that apply to the RTUC, STUC, and RTD; and 3) conducts the RTUC for the hourly pre-dispatch of Energy and Ancillary Services (CAISO Tariff)

TERM	DESCRIPTION
ICPM	Interim Capacity Procurement Mechanism as set forth in CAISO tariff section 43. (CAISO Tariff)
Imbalance Energy	The deviation of Supply or Demand from day-ahead Schedule, positive or negative, as measured by metered Generation, metered Load, or real-time Interchange Schedules. (CAISO Tariff)
Load Point Adjustment	A calculation that uses 3 prior hours (excluding the hour immediately prior to the event start) that adjusts the raw customer baseline using an established ratio. The resulting adjusted customer baseline is used as a basis to determine the RDRP Energy Measurement.
Local Regulatory Authority (LRA)	The applicable Local Regulatory Authority, e.g. the CPUC, utility board, etc. where a resource resides
Meter Data Reporting Deadline	The maximum allowed time from the end of a Demand Response Event (Normal Operations) to the time when meter data is required to be submitted for performance evaluation and settlement. The Meter Data Reporting Deadline may be either relative (a number of hours/days after Normal Operations) or fixed (a fixed calendar time, such as end-of-month).
Operating Procedure E-508B	An Operating Procedure of the CAISO that details the actions taken in response to forecasted or existing Operating Reserve deficiencies. The order of actions specified in OP E-508B may vary due to system conditions or other operational issues, such as skipping actions due to the severity of the situation.
PMax	The maximum normal capability of the Generating Unit. RDRP resources are modeled as generators; thus, this value is the maximum load reduction capability of a RDRP resource.
PMin	The smallest discrete load reduction possible for a RDRP Resource
PNode	A PNode or ‘Pricing Node’ is a single network node or subset of network nodes where a physical injection or withdrawal is modeled and for which a locational marginal price is calculated and used for financial settlement.
Ramp Period	The time between Deployment and Reduction Deadline, representing the period of time over which a Demand Resource is expected to achieve its change in Demand. (NAESB)
Ramp Rate	The rate, expressed in megawatts per minute, that a generator changes its output. (NERC Definition) Demand Resource ramp rate is the rate, expressed in megawatts per minute that a Demand Resource changes its Load.
Real-Time Market	The spot market conducted by the CAISO using SCUC and SCED in the real-time, after the hour-ahead scheduling process is completed, which includes the RTUC, STUC and the RTD for the purpose of Unit Commitment, Ancillary Service procurement, Congestion Management, and Energy procurement based on Supply Bids and CAISO Forecast of CAISO Demand. (CAISO Tariff)
Reduction Deadline	The time at the end of the Ramp Period when a Demand Resource is required to have met its Demand Reduction Value obligation. (NAESB)
Scheduling Coordinator	Scheduling coordinator; an entity certified by the CAISO for the purposes of undertaking the functions specified in CAISO tariff section

TERM	DESCRIPTION
	4.5.3 (CAISO Tariff)
Settlement Quality Meter Data	Meter data gathered, edited, validated, and stored in a settlement-ready format, for Settlement and auditing purposes. (CAISO Tariff)
Sub-LAP	A CAISO defined subset of PNodes within a Default LAP (CAISO Tariff)
Sustained Response Period	The time between Reduction Deadline and Release/Recall, representing the window over which a Demand Resource is required to maintain its reduced net consumption of electricity. (NAESB)
System Emergency	Conditions beyond the normal control of the CAISO that affect the ability of the CAISO Balancing Authority Area to function normally, including any abnormal system condition which requires immediate manual or automatic action to prevent loss of load, equipment damage, or tripping of system elements which might result in cascading Outages or to restore system operation to meet Applicable Reliability Criteria. (CAISO Tariff)
Use-Limited Resources	A resource that, due to design considerations, environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or other non-economic reasons, is unable to operate continuously on a daily basis, but is able to operate for a minimum set of consecutive trading hours each trading day. (CAISO Tariff)
VMax	The maximum hourly load curtailment capability of a RDRP resource that elects the COG model option.
VMin	For a RDRP resource that elects the COG model option, VMin = VMax – 0.01 MW.7

Attachment 2: Product Design Matrix

Product Description	Reliability Demand Response Product		
CAISO Model Employed:	**PDR-COG**	**Proxy Demand Resource**	
NAESB Baseline Methodology:	**Baseline Type I or II**	**Baseline Type I**	**Baseline Type II**
Overview:			
Market Clearing- Day-Ahead (If offer DA Energy)	Marginal		
Dispatch Type in Real-Time	Non-Marginal Dispatch in RT (Discrete/Block Dispatch)	Marginal Dispatch in RT	Marginal Dispatch in RT
NAESB Product Type	Energy Service		
Applicable CAISO Market	Real-time: Emergency Dispatch Only		
Trigger	Per CAISO Operating Procedure E-508B		
Scheduling/Bidding Interval	Hourly		
Aggregations	Custom and Default Aggregations by Sub-LAP		
Bidding Requirement	When resource is available, up to Availability Limits		
Curtailment Requirement	Mandatory		
Operating Period	Year-round		
Operating Hours	24 X 7		
RDRP Term	6 months with auto rollover (Opt Out): May-Oct & Nov-Apr		
Term Election Window	To Be Determined for Summer/Winter Term		
Availability Limits	Max 15 Events up to 48 hours per Term		
Dual Participation	Day-Ahead Energy and Real-Time Energy only; No A/S or RUC Participation		
Eligible M&V Methodologies	Baseline Type I, Baseline Type II (NAESB)		
Test Events	Up to 1 test event/year lasting up to 1 hour unless previously activated during calendar year		
Eligibility:			
Min Resource Size	500 kW per resource (smaller on exception basis; not less than 100kW)		
Max Resource Size	50 MW per resource	No Specified Limit	
Min Load Curtailment	≥ 500 kW per Resource (Exceptions with CAISO Approval)		
Advance Notification Period Ramp Period	Combined time not to exceed 40 minutes (Min Ramp Rate ≥ Pmax/40 minutes)		
Sustained Response Period	Minimum 4 Hour run-time capability		
Signed Pro Forma Agreement	CAISO RDRP Agreement		
Resource Owner/Rep	Demand Response Provider		
Scheduling/Dispatch/Settlement	Via a Scheduling Coordinator		
Resource Dispatch	Receive ADS dispatch instructions (by Resource and MW Quantity)		
Meter	LRA Approved Interval Meter		CAISO Approved Proxy Meter Data Plan
Meter Data Recording Interval	5 to 15 minute		CAISO Approved Proxy Meter Data Plan
Meter Data Availability	Event data plus data to cover Baseline Adjustment Window		
Sampling Precision & Accuracy	CAISO Approved Proxy Meter Data Plan w/ min Reqm't NAESB Phase II M&V Standard		
Real-time Telemetry	Not required		
SQMD Submission & Timing	5-minute Interval Data DA Energy Provision: Daily Submission Required RT Energy Only: Submission after an event		
Attributes:			
Aggregations	APNode		
Min On Time	≤ 1 Hour		
Max On Time	$\geq 4^{+}$ Hours		

Product Description	Reliability Demand Response Product		
CAISO Model Employed:	**PDR-COG**	**Proxy Demand Resource**	
NAESB Baseline Methodology:	**Baseline Type I or II**	**Baseline Type I**	**Baseline Type II**
Min Off Time	Resource Specific		
Max Start ups per Day	Resource Specific		
Ramp Rate (Worst/Best)	Resource Specific		
Advance Notification	Combined time not to exceed 40 minutes		
Ramp Period			
Min Load Cost	CAISO Calculated based on energy bid	$0	
Startup cost	$0	$0	
VMax Load (COG only)	Variable by Hour (up to Pmax in Master File)	N/A	
VMin Load (COG only)	Min Load=Max Load - 0.01 MW	N/A	
Max Load (PMax- masterfile value)	Resource Specific		
Min Load (PMin- masterfile value)	PMin = 0 MW		
Energy Bid	Single Segment Bid Resource Specific with Bid within: 95% Bid Cap ≤ Bid ≤ Bid Cap	Single or Multi-Segment Bid Resource Specific with Bid within: 95% Bid Cap ≤ Bid ≤ Bid Cap	
Geographic Constraint	SubLAP		
Gen Distribution Factor	CAISO Derived GDF Value		
Distribution Loss Factors	Applied by DRP per LRA requirements		
Self-schedule	No		
Performance Evaluation Methodology:			
NAESB Baseline Methodology	Baseline Type I or II	Baseline Type I	Baseline Type II
Measurement Type	Hourly Average		
Baseline Application	At Registration Level		
Baseline Description	10 in 10 non event days		
Baseline Adjustment	Multiplicative Load Point Adjustment; Symmetrical +/- 20%		
Adjustment Window	45 Days		
Performance Window	Demand Response Event		
Exclusion Rules	Event Days, Outages, /Local Transmission Emergencies, Testing Events		
Day Types	Weekends/Holidays & Weekdays		
Meter Data Source	Baseline Type I- LRA Approved Interval Meter Baseline Type II- CAISO Approved Proxy Meter Data Plan		
Meter Data Reporting Reqmt	DA Energy Provision: Daily Submission Required RT Energy Only: Submission Required only after a CAISO event or test		
Meter Data Reporting Level	At Registration Level		
Meter Data Submission	Data covering Event and Baseline Adjustment Window		
Meter Data Audit	Meter data available on demand, including data covering the baseline adj. window		
Meter Data Reporting Deadline	T+5B Noon		
SQMD	5-minute		
Sampling Precision & Accuracy	Baseline Type II- CAISO Approved Proxy Meter Data Plan (no less than as specified in NAESB M&V Standard, as applicable)		
Outage/Event Reporting:			
System	ISO's outage reporting system		
Timing of Outage or Event	Prior-to or During Event		

Product Description	Reliability Demand Response Product		
CAISO Model Employed:	**PDR-COG**	**Proxy Demand Resource**	
NAESB Baseline Methodology:	**Baseline Type I or II**	**Baseline Type I**	**Baseline Type II**
Reporting for Local Transmission Emergency Dispatch			
Reporting Reasons	Planned/Forced Outages, Local Transmission Emergency, Derated Resource		
Report	LTE Notification, Unavailable Capacity (MW), Reason for Unavailability, and Duration		

Attachment 3: ISO Reliability Events

Historical Record of ISO Reliability Events per Year:

TYPE	2004	2005	2006	2007	2008	2009	2010 YTD
Transmission Emergency	6	5	0	4	0	6	0
Warning	2	2	5	3	1	2	1
Stage 1	1	1	3	1	0	0	0
Stage 2	0	2	1	0	0	0	0
Stage 3	0	0	0	0	0	0	0
Warning Issued In Month(s):	Mar	Jul Aug	Jun Jul	Aug	Oct	Dec	Jan