Guidance Document on MRTU Release 1 Provisions to Support "Demand Response" Programs

1. Introduction

The objective of this document is to (1) summarize the CAISO market's capability that is available upon the start of the MRTU market (MRTU Release 1) to support demand response programs, using Non-Participating Load (NPL) functionality, (2) introduce a planned enhancement of the NPL functionality that the CAISO can make available shortly after the start of the MRTU market,[1] and (3) provide guidance on the ways in which MRTU Release 1 Participating Load (PL) functionality may be used in conjunction with IOU Demand Response programs.

Participating vs Non-Participating Loads

Participating Loads provide Curtailable Demand under a Participating Load Agreement between CAISO and the PL provider entity. Curtailable Demand is Demand from a Participating Load that can be curtailed at the dispatch direction of CAISO. SCs with Curtailable Demand may offer their product to CAISO to meet Non-Spinning Reserve or Imbalance Energy.

There are at least three types of Participating Load: 1) Pumping Load that is associated with a Pump-Storage resource, 2) A single Participating Load (i.e., Pumping and non-Pump Load) that is not associated with a Pump-Storage resource; and 3) Aggregated Participating Load (i.e. aggregated Pumping and non-Pumping Load) that is an aggregation of individual loads that operationally must be operating in coordination with each other. For the initial release of MRTU, depending on its attributes, the Participating Load can participate in CAISO Markets using one of two models that are supported by the CAISO Markets systems:

- Through a Pumped-Storage Hydro Units model, or
- Using a combination of Non-Participating Load Model and a Pseudo-Generator (Extended Non-Participating Load Model);

Non-Participating Loads may participate in the Day-Ahead Market (DAM) to procure Energy. The NPL Energy Bids may represent an aggregation of Loads, and must be bid-in and Scheduled at an Aggregated Pricing Node[2]. Non-Participating Loads may not participate in Ancillary Service markets, and may not be bid-in to be curtailed in the Real-time Market (RTM).

Under MRTU Release 1, a Demand Response program, depending on its nature may use either the Participating Load model or the Non-Participating model to formally participate in the CAISO markets for mutual benefit of the DR provider and the improved operational reliability of the system that benefits the Market Participants at large.

Distinguishing NPL Demand Response from Arbitrage in the Day-ahead Market

Bids in the DAM that use the NPL functionality may represent two types of market participants' price response in the Energy market, which the CAISO cannot distinguish without receiving information in addition to the NPL Energy bids:

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[1] This enhancement to the MRTU Release 1 NPL functionality has resulted from further CAISO review of stakeholder input at a Demand Response Working Group meeting on June 12, 2008. As the CAISO reviewed detailed design assumptions for the Post-Release 1 implementation of Dispatchable Demand Resources (the results of which will be reflected in the Draft Final Proposal for Post-Release 1 functionality), stakeholders also requested an improvement in how demand response is incorporated in the DAM Residual Unit Commitment (RUC) process in Release 1.

[2] An Aggregated Pricing Node (APnode) consists of a predefined set of network nodes for which Locational Marginal Prices (LMPs) are computed. The LMP for an APnode is the LDF-weighted average of its constituent Pricing Node LMPs.

(a) Demand response, i.e., conditional commitment to reduce consumption based on the demand bid submitted in the DAM.[3] Here, the NPL entity plans to reduce real-time consumption based on the DAM prices, i.e., to not consume the bid-in demand that did not clear the DAM.

(b) Financial arbitrage between day-ahead and real-time Energy prices. Here, the NPL entity purchases Energy to serve part of its load in the DAM, based on a price-quantity curve it submits in the DAM, and shifts the purchase of Energy to serve its remaining load to the Real-Time Market (RTM).

In either case, the NPL bidding in the DAM can set the day-ahead price for the corresponding Aggregated Pricing Node.

Although the CAISO cannot distinguish between these two types of bids in DAM, it is important for the CAISO to separate their impacts on subsequent market operations because the CAISO will reduce its RUC procurement target based on the anticipated demand response, but not based on the financial arbitrage between DAM and RTM. The central issue for the Market Participants is how to declare, and for the CAISO how to distinguish, a NPL bid segment that is intended for arbitrage from one that is intended as Demand Response. In its initial implementation, MRTU Release 1 provides two methods for demand response in this regard:

(1) The Load Serving Entity (LSE) Scheduling Coordinator (LSE SC) can inform the CAISO prior to the DAM of the demand response that it has triggered or intends to trigger for specific hours on the Operating Day. The LSE SC would account for the corresponding DR MW in its DAM schedule, i.e., would reduce its scheduled or bid load in the IFM accordingly (to avoid buying energy in IFM to serve it), and the CAISO will reduce its RUC procurement target under section 31.5.3.2 of the MRTU tariff accordingly.

(2) The LSE may designate its demand response as a Participating Load (PL), using the so-called Extended Non-Participating Load functionality to allow demand response to participate in the DAM.[4]

Organization of the Document

The two methods mentioned above are explained in sections 2 and 3, respectively. Further detail for the first method is documented in the Demand Response Resource – Release 1 User Guide, available at http://www.caiso.com/1cbb/1cbbc224c9a0.html.

The second method is described in detail in CAISO's Business Practice Manual for Market Operations, available at http://www.caiso.com/17e9/17e9d7742f400.html.

After MRTU's initial implementation, the CAISO can further expand these options. The enhancements of the NPL functionality that the CAISO can make available shortly after the start of the MRTU market are described in section 4.

Examples are provided in each section to illustrate how DR programs can use the MRTU features and functions under the respective model. Section 5 provides additional examples with a view to future MRTU enhancements.

2. Recognition of Demand Response Using Non-Participating Load under MRTU Release 1 (Method as Identified in User Guide from Working Group I)

Recognizing the limitations in the MRTU Release 1 functionality for Participating Load (PL) resources, the CAISO, in collaboration with the stakeholders, identified a workaround that allows Participating Loads to use NPL functionality to provide demand response under MRTU Release 1 with the following features, functions, and limitations:

3 Day-ahead schedules are financially binding, but do not restrict the amount of demand that appears in real-time.

4 MRTU Release 1 also provides a Pumped-Storage Hydro Unit model as an option for Participating Loads, but this is not described in detail herein because it does not allow aggregation of multiple Loads.

Day-Ahead Market (Integrated Forward Market):

- Day-Ahead Demand Response Programs
    - do not explicitly participate in the DAM. The impact on the day-ahead market-clearing schedules and/or prices is embedded in overall NPL schedules, along with financial arbitrage.
    - are initiated by LSEs (or more precisely the LSE SC).
    - are triggered by various conditions that may or may not be part of CAISO's market information, such as day-ahead forecast temperature, day-ahead forecast demand, high price forecasts, etc.
- The LSE SC notifies the CAISO through a manual process (an Excel spreadsheet), prior to the close of the DAM at 10:00 a.m., regarding the quantity and location of the DR they intend to trigger (DR forecast)
- The DR location granularity is at the LAP level, or possibly at smaller zones in the future[5]. In other words, the DR will use the same weights (Load Distribution Factors) as the LAP in which they are located.

RUC:

- CAISO adjusts the RUC procurement target based on DR MW quantities that the LSE submitted prior to the close of the DAM. In doing so, CAISO will take into account past performance of the corresponding DR, and based on their historical performance may adjust the RUC procurement target based on a fraction (between 0 and 1) of the DR MWs.
- NPL DR can not directly participate in RUC, and therefore, the forecast DR MW quantity does not get paid any RUC availability for the reduction in the RUC procurement target. Instead, when the DR has reduced the LSE's real-time Demand, the LSE's RUC obligation (which equals the LSE's real-time Demand minus the LSE's day-ahead Schedule) is reduced in Settlements. In other words, the DR entity benefits from (1) reduction of its unscheduled load exposure to real-time market; (2) reduction of its Tier 1 RUC allocation; (3) reduction of its neutrality charge allocation based on metered demand; in addition it benefits from (4) socialized cost reduction due to potential reduction of NPL costs due to reduced LAP LMPs associated with lower demand, and (5) socialized cost reduction due to reduction of RUC costs.

Real-time:

- The LSE may trigger "Day-of" DR Programs. For the CAISO to consider "Day-of" programs in the CAISO Forecast of CAISO Demand (CFCD), the LSE must submit the corresponding DR forecasts to the CAISO before the close of the real-time market (T-75 min.)
- The CAISO reduces the CFCD[6] based on the combination of Day-ahead DR and Day-of DR, in Short-Term Unit Commitment (STUC), Real-Time Unit Commitment (RTUC), Hour-Ahead Scheduling Process (HASP), and Real-Time Economic Dispatch (RTED) processes.
- NPL DR does not participate in the real-time market explicitly. The Day-ahead and Day-of DR that is triggered will be indirectly settled in real-time implicitly as part of the real-time uninstructed load deviation settlement (based on the difference between the day-ahead load schedule and real-time metered demand of the LSE's SC.)

  Note: The real-time settlement is based on a single Scheduling Coordinator per demand meter.

Example 1: Illustrating the use of NPL Functionality for Demand Response

Assume a Load Serving Entity with a base load of 100 MW in an IOU LAP has a 10 MW Critical Peak Pricing program.

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5 Initially the LAPs will be the three Default LAPs and MSS LAPs. An example of smaller zones that would be used in the future is the Local Capacity Areas that define local resource adequacy requirements.

6 The CFCD is based on historical unadjusted load (i.e., actual load plus any load that was curtailed due to Demand Response).

Assume the DR is slated by the LSE SC to be triggered for 4 hours (HE 1400 to HE 1700) the next operating day. The LSE SC submits a demand bid into the DA IFM to arbitrage between day-ahead and real-time prices for the non-DR portion (90 MWs). For simplicity, assume the bids, system and market conditions are the same for each of the 4 hours, and that the LSE's demand bid consists of 50 MW as price taker, 25 MW bid at $60/MWh, and 15 MW bid at $30/MWh as shown below.

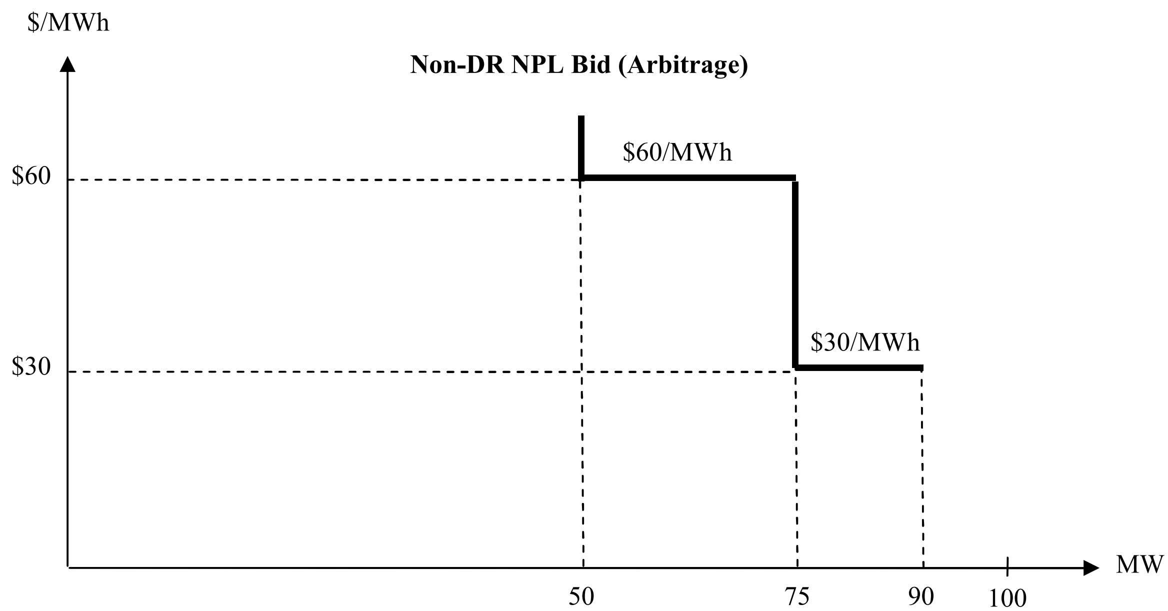

Figure 1 – Price-Responsive NPL Arbitrage Bid

Assume the IFM LAP LMP is $40/MWh. So, 75 MW of the LSE's load clears the IFM. The LSE is charged $40*75 = $3,000 for each of the 4 hours.

In RUC, the CAISO reduces its RUC procurement target by 10 MW[7], i.e., the amount called under the CPP program.

Assume the RUC Tier 1 price is $10/MW/hr.

Assume the real-time LAP LMP is $50/MWh. Consider two scenarios (a) and (b) as described below:

(a) The LSE's real-time consumption is 90 MW. The LSE is charged as follows:

- Energy charge: $50*(90-75) = $750 for each of the four hours
- Tier 1 RUC charge: $10*(90-75) = $150 for each of the four hours
- Tier 2 RUC and any other neutrality charges based on 90 MW of real-time consumption

(b) The LSE's real-time consumption is 100 MW (i.e., the DR was not actually triggered by the LSE). The LSE is charged as follows:

- Energy charge: $50*(100 - 75) = $1,250 for each of the four hours
- Tier 1 RUC charge: $10*(100 -75) = $250 for each of the four hours
- Tier 2 RUC and any other neutrality charges based on 100 MW of real-time consumption.

Comparison of the two scenarios indicates a first order gain by the LSE due to the triggered DR as follows:

- A gain of $600/hr for Energy and Tier 1 RUC costs: ($1,250 + $250) – ($750 + $150) = $600

[7] This amount is the difference between 100 MW base and 90 MW of Price-Responsive NPL.

- A 10% reduction of Tier 2 RUC and other neutrality charges (cost allocation based on 90 MW under scenario (a) vs 100 MW under scenario (b)).

However, there may be additional gains to the LSE for triggering the DR (or equivalently, there may be revenue loss to the LSE for not triggering the DR). For example, under scenario (b) since less RUC capacity is available for use by the CAISO in the real-time market, there is less real-time competition, and potentially a steeper slope for the real-time LAP LMP. The 10 MW additional real-time consumption may thus result in an increase of the real-time LAP LMP from $50/MWh to a higher level with attendant cost increase to the LSE.

3. Participating Loads under MRTU Release 1

The MRTU Release 1 functionality allows Participating Loads to bid into the CAISO's day-ahead and real-time Energy and Ancillary Service markets. The Participating Load model under MRTU Release 1 relies on (1) a simple price-sensitive demand curve submitted in the DA market, and (2) an accompanying pseudo-generator for use in the Real-time Market that represents the demand response resource's dispatch capability. This will be the Participating Load model that serves for the interim until the CAISO releases the Dispatchable Demand Resource model under MAP (and as discussed in Working Group 2). Thus a LSE SC can bid price-responsive DR programs into the CAISO markets, but with the following possibilities and limitations:

- After execution of a Participating Load Agreement, the PL consumer requests a Custom Load Aggregation Point (Custom LAP) from the CAISO, and upon CAISO approval, receives a unique Resource ID for the DR resource as well as a unique Resource ID for the associated pseudo-generator. The LSE SC can, thus bid or schedule all or part of its DR Resource in the Custom LAP for Energy in DAM using the unique load Resource ID. This Demand Bid in DAM for the Custom LAP is presumed to represent actual price-responsive Demand. The LSE SC can also use the pseudo-generator Resource ID to submit Non-spinning Reserve bid into CAISO's DAM.
- The Price Responsive Demand (up to 10 bid segments) under this Resource ID is submitted using the PL's Custom LAP, and meter data for Settlement is submitted for the same Custom LAP. The Custom LAP distribution factors are preserved in the IFM market-clearing process.
- The DR curve may include segments from different DR programs, at the LSE's discretion, if they share the same Custom LAP. However, this identification is for the LSE's internal bookkeeping and does not affect the CAISO's market clearing and pricing process.
- The maximum MW of the PL's DR bid does not have any significance for Settlements. The CAISO will establish a methodology for calculating the baseline usage that represents the PL's Demand that would occur if the PL did not respond to the CAISO's scheduling and dispatch, for purposes of DR compliance.
- The CAISO will not reduce the RUC procurement target based on the PL's day-ahead schedule. However, the expected demand of PL resources is not included in the CAISO's RUC procurement. In other words, in the RUC process, the day-ahead PL schedule is used as the forecast for PL's consumption.
- There will be no RUC payment to the DR resource. However, when PL performs (curtails consumption in real-time according to its day-ahead schedule), assuming there is no day-ahead under-scheduling of PL DR demand,, the PL resources are exempt from Tier 1 RUC charges[8].
- In the real-time market, the CAISO Forecast of CAISO Demand (CFCD) considers PL resources separately. In other words, the Participating Load's schedule becomes the CAISO's forecast for the amount of the Participating Load. Stated differently, the PL schedule and forecast are the same. To the extent the PL actually reduces in demand the RT forecast will automatically adjust based on the feedback of the actual System Load into the RT Demand Forecast.
- There is no PL DR performance requirement in CAISO's Energy markets[9]. To the extent the PL consumes more or less than its day-ahead schedule (based on its metered demand), the difference from its day-ahead schedule is settled at the real-time price for its Custom LAP.

[8] In rare cases where CAISO dispatches the PL to increase consumption in real-time, the instructed consumption increase is exempt from Tier 1 RUC charges.

- PL resources are eligible to participate in AS markets for non-spinning reserve, subject to the CAISO's established technical and compliance standards. In MRTU Release 1, non-spinning reserve bids must be for contingency-only reserves.
- The LSE SC must self schedule (as price taker) sufficient load in the Custom LAP under its load Resource ID to cover all of the Non-spinning Reserve MWs it bid in the day-ahead market. However, this is requirement is not checked and enforced in MRTU Release, i.e., there is no SIBR rules that ensure sufficient demand is schedules to support the Non-Spin on Pseuedo-Generator. In case, the amount of Custom LAP load that clears the IFM is not enough to cover the awarded day-ahead Non-spinning Reserve, then, the LSE SC will be subject to Ancillary Service "No Pay" charges.
- Real-time dispatch instructions may be given (for the pseudo generator to produce Energy from any Non-spinning Reserve capacity awarded to the pseudo-generator) under contingency conditions. However, for settlement purposes, the response of the pseudo-generator is tracked by comparing the change in the Custom LAP load before and after the dispatch instruction[10].

Example 2 – Illustrating Participating Load Functionality in MRTU Release 1

This example illustrates the use on the Extended NPL functionality for a DR Resource that would like to participate in the Energy Market, but not in the AS market. The case where the DR resource participates in the AS markets as well is presented later in Example 5.

Assume a Load Serving Entity with a base load of 100 MW in an IOU LAP has identified and registered 10 MW of its demand as Participating Load within a Custom LAP (i.e., has offered to reduce consumption by up to 10% from takeout points in the Custom LAP, where the Custom LAP is entirely within an IOU LAP).

The 10 MW of PL DR is bid with the first 6 MW at $65/MWh and the remaining 4 MW at $45/MWh as shown below.

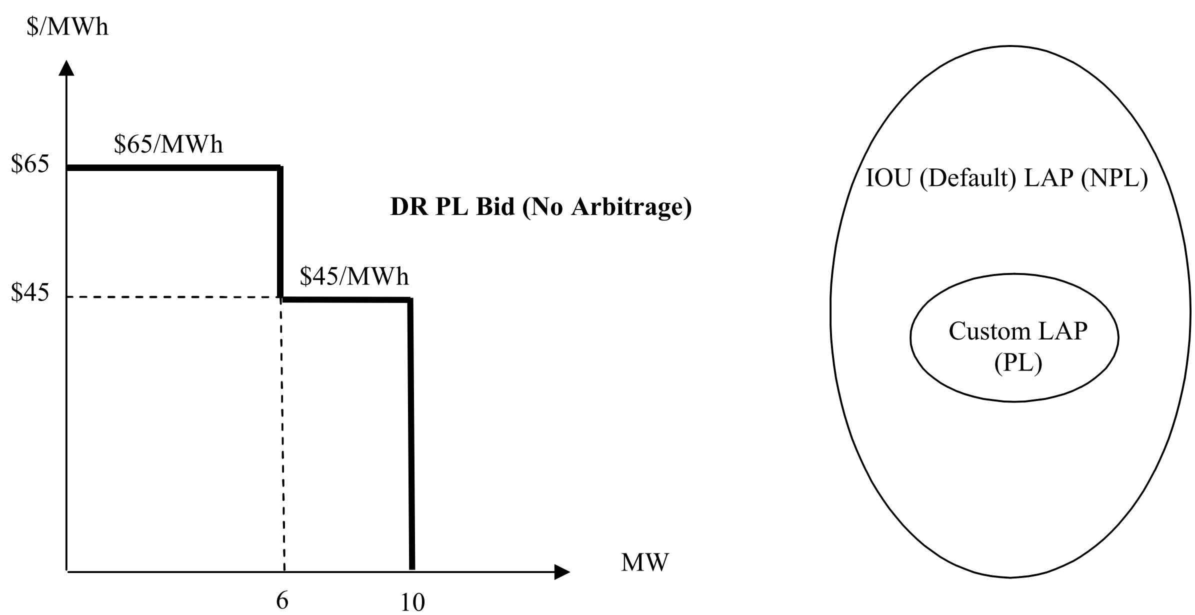

Figure 2 – DR PL Bid (No Arbitrage) under Extended NPL Model

[9] However, there will be reporting obligations to the extent the Price Sensitive DR is claimed by the LSE as part of its DR/RA obligation.

[10] The PL providing AS (Non-spinning Reserve) must have telemetry.

The LSE SC's demand bid (for day-ahead vs real-time market arbitrage) consists of 50 MW as price taker, 25 MW bid at $60/MWh, and 15 MW bid at $30/MWh (similar to Example 1 above). These bids are for the Non-Participating portion of the LSE's demand and are thus treated as bids at the IOU LAP rather than the Custom LAP. For ease of reference, we will refer to this as the NPL load of the LSE.

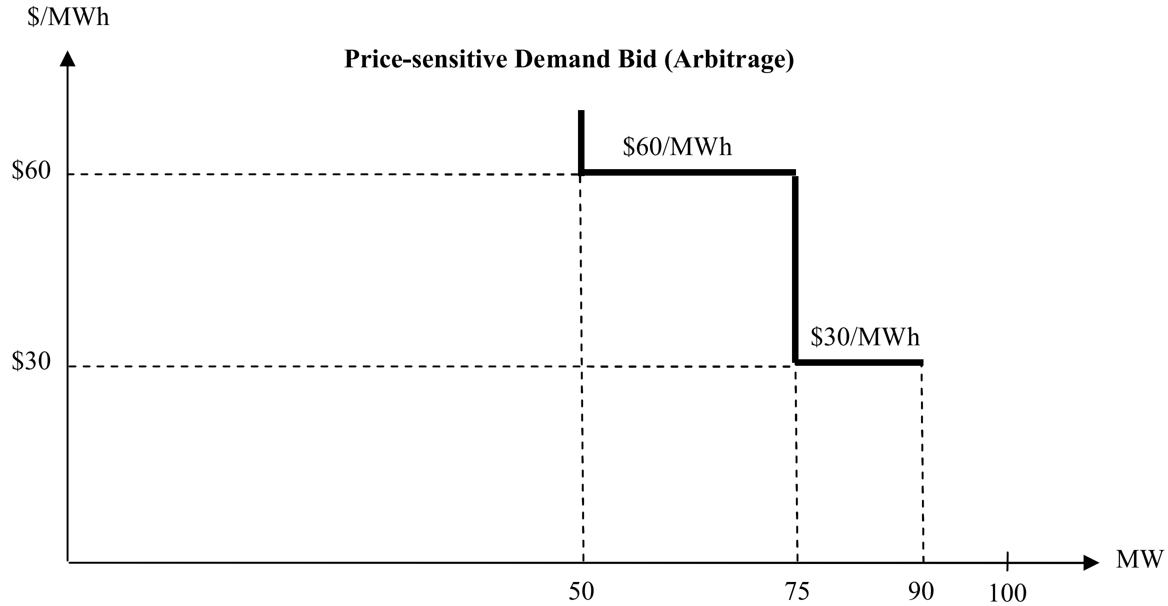

Figure 3 – Price-Responsive Demand Bid (Arbitrage) under Extended NPL Model

Assume the IFM IOU LAP LMP is $40/MWh and the day-ahead Custom LAP LMP is $50/MWh. So, 6 MW of PL and 75 MW of the NPL load clear the IFM. The LSE is charged $40*75 + $50*6 = $3,300 per hour.

In RUC the CAISO uses its load forecast which includes 96 MW (the NPL demand forecast of 90 MW and the PL schedule of 6 MW) for this entity. Assume the RUC Tier 1 price is $10/MW/hr.

For the real-time market assume the PL retains its day-ahead bids for use in the real-time market. In other words, the pseudo-generator bid looks as follows:

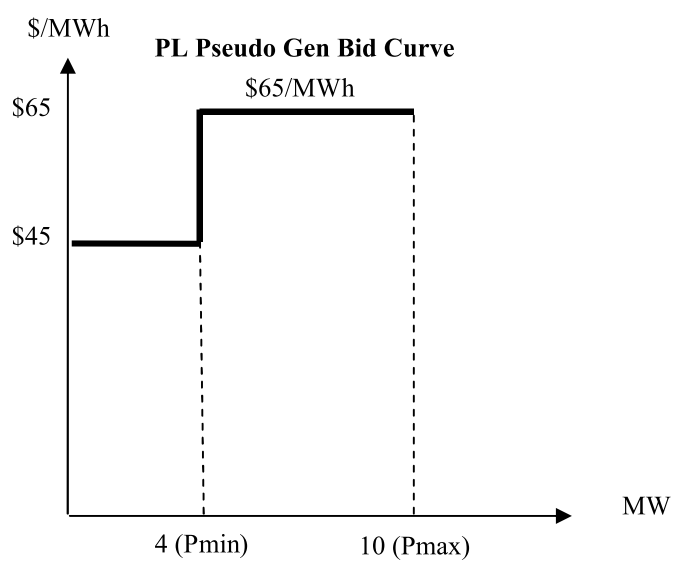

Figure 4 – Real-time Pseudo-Generator Bid under PL Model

Let us consider two Cases:

Case 1: Assume the real-time LAP LMP is $50/MWh in the IOU LAP and $60/MWh in the Custom LAP. In this case the $65/MWh PL pseudo-generator is not dispatched. Consider three scenarios as described below:

(a) The LSE's real-time consumption is 90 MW for NPL and 6 MW for PL (the DR performs). The LSE is charged as follows:

- Energy charge: $50*(90 - 75) + $60 (6 - 6) = $750 per hour
- RUC charge: $10*((90 + 6) – (75 + 6)) = $150 per hour
- Tier 2 RUC and any other neutrality charges based on 96 MW of real-time consumption (sum of NPL and PL MW consumption).

(b) The LSE's real-time consumption is 90 MW for NPL and 10 MW for PL (i.e., the DR did not actually perform). The LSE is charged as follows:

- Energy charge: $50*(90 - 75) + $60 (10 - 6) = $990 per hour
- RUC charge: $10*(100 - 81) = $190 per hour
- Tier 2 RUC and any other neutrality charges based on 100 MW of real-time consumption (sum of NPL and PL MW consumption).

(c) The LSE's real-time consumption is 90 MW for NPL and 0 MW for PL (i.e., the DR provider curtails the entire 10 MW of PL as a block). The LSE is charged as follows:

- Energy charge: $50*(90 - 75) + $60 (0 - 6) = $390 per hour
- RUC charge: $10*(90 -81) = $90 per hour
- Tier 2 RUC and any other neutrality charges based on 90 MW of real-time consumption (sum of NPL and PL MW consumption).

Case 2: Assume the real-time LAP LMP is $60/MWh in the IOU LAP and $70/MWh in the Custom LAP. In this case the pseudo-generator $65/MWh PL segment (6 MW) is dispatched. Consider three scenarios as described below:

(a) The LSE's real-time consumption is 90 MW for NPL and 0 MW for PL (the DR performs both with respect to its day-ahead schedule and real-time dispatch instruction). The LSE is charged as follows:

- Energy charge: $60*(90 - 75) + $70 (0 - 6) = $480 per hour
- RUC charge: $10*(90 -81) = $90 per hour
- Tier 2 RUC and any other neutrality charges based on 90 MW of real-time consumption (sum of NPL and PL MW consumption).

(b) The LSE's real-time consumption is 90 MW for NPL and 10 MW for PL (i.e., the DR did not actually perform the day-ahead slated curtailment, or the real-time dispatch). The LSE is charged as follows:

- Energy charge: $60*(90 - 75) + $70 (10 - 6) = $1,180 per hour
- RUC charge: $10*(100 - 81) = $190 per hour
- Tier 2 RUC and any other neutrality charges based on 100 MW of real-time consumption (sum of NPL and PL MW consumption).

(c) The LSE's real-time consumption is 90 MW for NPL and 6 MW for PL (i.e., the PL DR provider did not follow the real-time dispatch, but did curtail based on day-ahead market schedule). The LSE is charged as follows:

- Energy charge: $60*(90 - 75) + $70 (6 - 6) = $900 per hour
- RUC charge: $10*(96 -81) = $150 per hour

- Tier 2 RUC and any other neutrality charges based on 96 MW of real-time consumption (sum of NPL and PL MW consumption).

4. Post-MRTU Release 1 Functionality: "Proxy Demand Resource" - NEW

The CAISO recognizes that the options described in sections 2 and 3 may not provide all of the functionality that will be needed to integrate price-responsive DR programs in MRTU Release 1. In particular:

- for DR programs that are embedded in the IOU load (non-Participating Load) it can be difficult to anticipate the MW quantity of DR from the price-responsive DR programs before the DAM has run, for submission of RUC adjustments to the CAISO, and
- for DR programs that use the Participating Load model (Extended Non-Participating Load model for Aggregate Demand Response programs) it can be difficult to maintain demand forecasts for scheduling of Custom LAPs supporting DR programs that have changes in customer enrollments from month to month.

The CAISO plans to expand the Non Participating Load functionality[11] shortly (a few months) after the start of the MRTU market to address these remaining needs, with the following features and functions, which comprise a "Proxy Demand Resource" (PDR):

- Like the Non-Participating Load functionality described in section 2, the load that underlies the Proxy Demand Resource is scheduled using the Default LAP as Non-Participating Load. As detailed below, however, although the DR MW quantity is included in the Default LAP NPL MW as price taker, the DR bid segments are provided using a separate proxy generator resource.[12]
- To support the scheduling of price-responsive DR, the NPL DR Provider will register, under a separate unique Resource ID, the portion of its demand that is price-responsive. This separate "portion" of the demand is registered as a generator resource described herein as a "Proxy Demand Resource".
- The PDR's bid must be submitted for aggregations of DR loads within a Local Capacity Area as defined for Resource Adequacy purposes (or for the remaining area within a Default LAP that is not within a Local Capacity Area), or may be submitted for DR resources for smaller areas within a Local Capacity Area (e.g., nodal level).

  Note[13]: The proxy generator used in PDR should not be confused with the pseudo generator used in the Participating Load model (called Extended Non-Participating Load model and explained in section 3). There are two important differences:

  - Unlike the pseudo generator used for the Extended NPL model, the proxy generator in the PDR model is not meant to be used for provision of Ancillary Services. The intent of the PDR model is to help the non-dispatchable DR programs formally participate in CAISO's day-ahead market.
  - Whereas the pseudo generator used for the Extended NPL has the same spatial granularity as the Custom LAP where the PL load resource is defined, the PDR proxy generator may be defined at a node or an aggregation of nodes within a Local Capacity Area, even though the DR demand is scheduled at the default IOU LAP.
- The energy bid for a PDR has the structure of a generator, including:
  - an Energy Bid curve (up to 10 bid segments), and/or

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11 The option described here is in addition to the MRTU Release 1 Extended Non-Participating Load functionality for Participating Loads, which is described in section 3.

12 The Settlement treatment described in this section will account for the price-responsive DR that is scheduled in the CAISO markets. Since the DR price-quantity bids are provided through the proxy generator, the CAISO expects that any price-based bid segments that appear in the NPL energy bid will only represent financial arbitrage.

13 The PDR design is currently fleshed out for the Day-ahead Energy market. However, the CAISO DR design team is considering possible enhancements of the PDR design to support Real-time Imbalance Energy and Day-ahead Non-spinning Reserve.

- a Load Reduction Initiation Cost and/or a Minimum Load Reduction Cost, which are registered in the CAISO's Master File using the start-up and minimum load cost components of a generator.

Note: Under the CAISO's Markets and Performance (MAP) market design initiative, the Load Reduction Initiation Cost and a Minimum Load Reduction Cost may be included in daily bids for a Dispatchable Demand. However, for a PDR these components must be registered in the Master File since the CAISO is making the PDR functionality available in advance of MAP.[14]

- The Energy Bid curve for the PDR may include segments from different DR programs operated by the DR Provider, at the DR Provider's discretion, provided that these DR programs apply to the same Local Capacity Area. However, this segmental identification is for the DR Provider's internal bookkeeping and is immaterial to CAISO's market clearing and pricing process.
- Although the PDR's scheduling and dispatch can impact LMPs, the cleared PDR not subject to LMP-based Settlement. This is because the PDR as a "Proxy Generator" is not an actual generator, and will not have a metered output.[15] The CAISO will determine whether from an implementation point of view the PDR schedule can be omitted from the data received for Settlement, or alternatively the final output of the PDR (Proxy Generator) be reported as zero. Instead of the PDR being subject to Settlement, the CAISO will subtract the schedule and dispatch of the PDR (Proxy Generator) from the schedule of the underlying demand at the Default LAP, which will be settled at the Default LAP price. In other words, the cleared DR MW quantity is netted out of the LSE SC's demand quantity for day-ahead settlement. This is to ensure that the PDR functionality remains within the bounds of what can be implemented prior to implementation of the Dispatchable Demand Resource functionality in MAP, and to avoid creating a "money machine" whereby the LSE can buy energy at the Default LAP price for its demand schedule and then sell it back at a higher, nodal or custom aggregation, price in the same market.
- The CAISO will reduce the RUC procurement target based on the PDR's schedule. Alternatively, the PDR implementation may avoid adjusting the RUC procurement target, and simply use the IFM output of the PDR (Proxy Generator) in RUC. This allows the PDR to provide price-responsive bidding in the CAISO markets that the CAISO can then use as an adjustment in the RUC process, instead of requiring LSEs to estimate how much price-responsive DR would be dispatched before the DAM has run.
- The PDR is not a resource that can be reserved in the RUC process (stated differently, the PDR represented by the "Proxy Generator" is already scheduled in IFM and not in RUC), and thus there will be no RUC payment to the PDR.
- In the real-time market, the CAISO Forecast of CAISO Demand (CFCD) is reduced in STUC, RTUC, HASP, and RTED processes based on the Day-ahead DR award.
- The LSE that schedules using the PDR functionality benefits from the DR that it schedules through the CAISO markets through three mechanisms: (1) the LSE achieves a reduced Demand schedule for Settlement purposes because the CAISO will subtract the Proxy Generator's schedule from its NPL Demand schedule, (2) the CAISO will know after the Integrated Forward Market produces day-ahead schedules, before the RUC process starts, what the schedule is for the PDR, and will factor the PDR's schedule in as a reduction to the RUC procurement, and (3) scheduling of the Proxy Generator can result in relieving local congestion, reduced LMPs, and reduced Default LAP price, which reduces the cost of serving the load at the Default LAP.[16]

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[14] The MRTU Post Release 1 Participating Load functionality in MAP will accommodate all three cost components as part of the PL bid structure.

[15] While the response of a PDR might be inferred by comparing end-use metering against a calculated baseline consumption, this process has not been established at this time, and further does not constitute Settlement Quality Meter Data under MRTU Release 1. In the PDR functionality, calculations of baseline consumption will be considered for purposes of program monitoring, but the PDR functionality is designed to avoid Settlements and Compliance requirements other than Settlement of the underlying NPL.

[16] LAP price settlement instead of "locational" settlement with NPL DR, can result in net revenue or cost due to marginal loss and congestion price differences between the DR location and the LAP. The net

- The PDR's energy bid can set market prices, but dispatch at the PDR's minimum load will not set the market-clearing prices. Thus, the Load Reduction Initiation Cost and the Minimum Load Reduction Cost do not directly affect market-clearing prices.
- There will be no Bid Cost Recovery for the PDR resource. The Load Reduction Initiation Cost and the Minimum Load Reduction Cost are used only in the process of resource commitment and scheduling. If a PDR chooses to use these components, they will affect the PDR's scheduling, which may or may not result in the PDR being scheduled such that these costs will be recovered from market revenues.
- DR is considered non-participating load, and as such there is no PDR performance requirement in CAISO's markets[17]. To the extent the PDR as non-participating load consumes more or less (based on its metered demand) the difference between its day-ahead schedule and its metered demand will be settled at the real-time LAP price.
- PDR cannot participate in AS markets.

Example 3 – Illustrating the use of Proxy Demand Resource for Demand Response Bidding, Scheduling, and Settlement

Assume a Load Serving Entity with a base load of 100 MW in an IOU LAP has identified and registered 10 MW of its demand as Proxy Demand Resource (PDR) in a Local Capacity Area within the IOU Default LAP (i.e., has offered to reduce consumption by up to 10% from takeout points in the Local Capacity Area, which may be a sub-LAP of the IOU LAP). The entity's PDR in fact consists of two distinct DR programs that are callable in the same Local Area. One program represents a 4 MW block (ON-OFF) load and the other program represents 6 MW of continuously adjustable load. The DR provider decides to register this as a PDR with $0 Load Reduction Initiation Cost, $180/hr of Minimum Load Reduction Cost ($45/MWh for the 4 MW of block DR), and bids the 6 MW of its adjustable DR load at $65/MWh.

The LSE also would like to bid its 90 MW of demand (for day-ahead vs real-time market arbitrage) with 25 MW bid at $60/MWh, 15 MW bid at $30/MWh, and the remaining as price taker.

The entity will submit the following bids to accomplish this using PDR functionality:

- Submit demand at the Default LAP consisting of 60 MW price-taker Default LAP load (50 MW for actual NPL, and 10 MW for the DR), 25 MW Default LAP load bid at $60/MWh, and 15 MW Default LAP load bid at $30/MWh as shown below.

revenue/cost will be allocated to congestion (CRR Balancing Account) and marginal loss surplus accordingly.

17 However, there will be reporting obligations to the extent the Price Sensitive DR is claimed by the LSE as part of its DR/RA obligation.

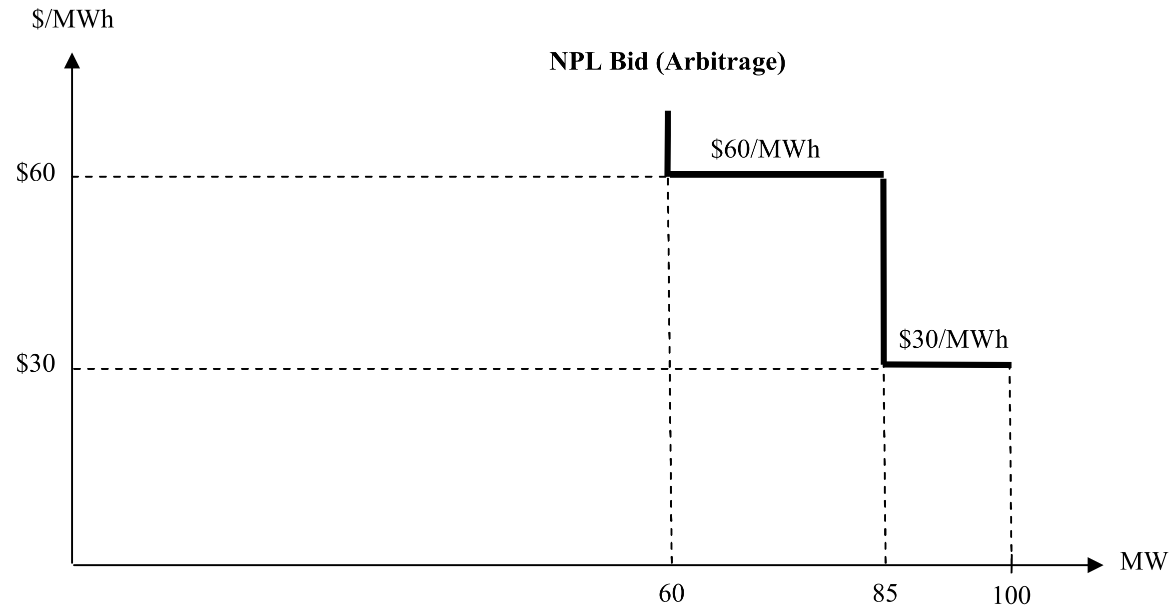

Figure 5 – Price-Responsive Demand Bid (Arbitrage) under PDR Model

- PDR (Proxy Generator) bid consisting of three parts, namely, $0 proxy start up cost (Load Reduction Initiation Cost, from Master File), $180/hr of proxy minimum load cost (Minimum Load Reduction Cost from Master File), and proxy Energy bid above minimum load of 6 MW at $65/MWh as shown below.

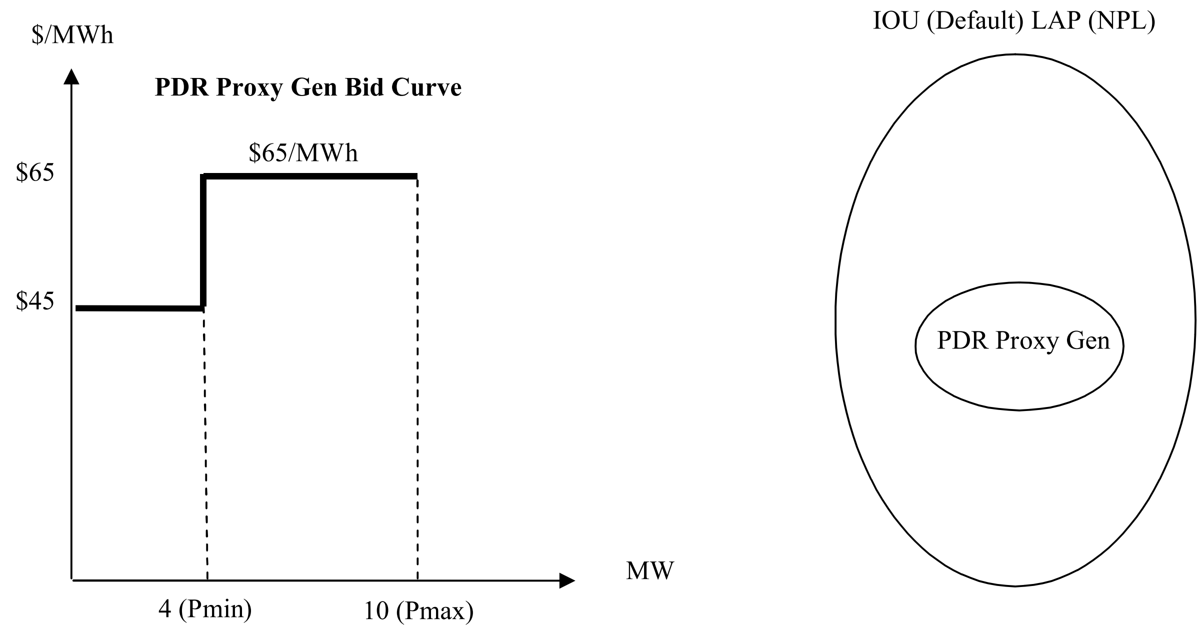

Figure 6 – Proxy Demand Resource (Proxy Generator) Bid under PDR Model

Assume the IFM Default LAP LMP is $40/MWh and the PDR Proxy Gen LMP is $50/MWh. So, 85 MW of the Default LAP load will clear and the PDR is scheduled at its minimum load of 4 MW (since the optimization finds it economic to schedule it at a minimum load at an effective price of $180/4 = $45/MWh).

The net Default LAP load is thus: 85 – 4 = 81 MW and the entity is charged $40*81 = $3,240 per hour. In other words, although the PDR Minimum Load Cost is $180, it is effectively settled at $160 (by netting the NPL LAP load) with no Bid Cost Recovery. This is appropriate because the same 40 MW were effectively charged only $40*4 = $160 as part of the price-taker portion of the NPL.

Note: Comparing this result with that of Example 2 (which is practically the same situation modeled as PDR here), note that in Example 2, the entity was charged $3,300 for 81 MW, whereas in this example the entity is charged $3,240 for the same quantity.

In RUC the CAISO reduces its RUC procurement target by the quantity of PDR (Proxy Generator) scheduled in the IFM, i.e., 4 MW[18]. Assume the RUC Tier 1 price is $10/MW/hr.

For the real-time market assume the real-time Default LAP LMP is $50/MWh and the Proxy Generator LMP is $60/MWh. Consider two scenarios as described below:

(a) The LSE's real-time consumption is 96 MW (90 MW for its non-DR load and 6 MW for DR that remained scheduled as load in IFM), in other words the DR performed. The LSE is charged as follows:

- Energy charge: $50*(96 - 81) = $750 per hour
- RUC charge: $10*(96 -81) = $150 per hour
- Tier 2 RUC and any other neutrality charges based on 96 MW of real-time consumption.

(b) The LSE's real-time consumption is 100 MW (i.e., the DR did not actually perform). The LSE is charged as follows:

- Energy charge: $50*(100 – 81)) = $950 per hour

  Note: Comparing this result with that of Example 2, Case 1(b), note that in Example 2, the entity was charged $990 for 19 MW real-time load deviation, whereas here it is charged $950 for the same quantity.

- RUC charge: $10*(100 - 81) = $190 per hour
- Tier 2 RUC and any other neutrality charges based on 100 MW of real-time consumption (sum of NPL and PL MW consumption).

5. Comparative Examples

The intent of the examples in this section is to further illustrate the possibilities and implications of:

- using the Participating Load functionality (Extended Non-participating Load) vs the PDR model for DR programs that participate only in the Energy market; such as the Critical Peak Pricing (CPP) program
- using the Participating Load functionality (Extended Non-participating Load) for DR programs that can participate in both Energy and AS markets; such as the Capacity Bidding (CBP), PeakChoice, and Aggregate Managed Portfolio (AMP) programs.

Example 4: Using Participating Load (Extended NPL) vs PDR Model for DR Energy

Consider a simple three-node network, with Generation at 2 nodes, a LAP consisting of 2 of the nodes, and Participating Load Demand Response at one of the nodes as shown in the Figure 7 below. One of the generators (G1) is located outside of the Default LAP.

18 Alternatively, the PDR may be implemented in such a way that the output of the proxy generator is used in RUC.

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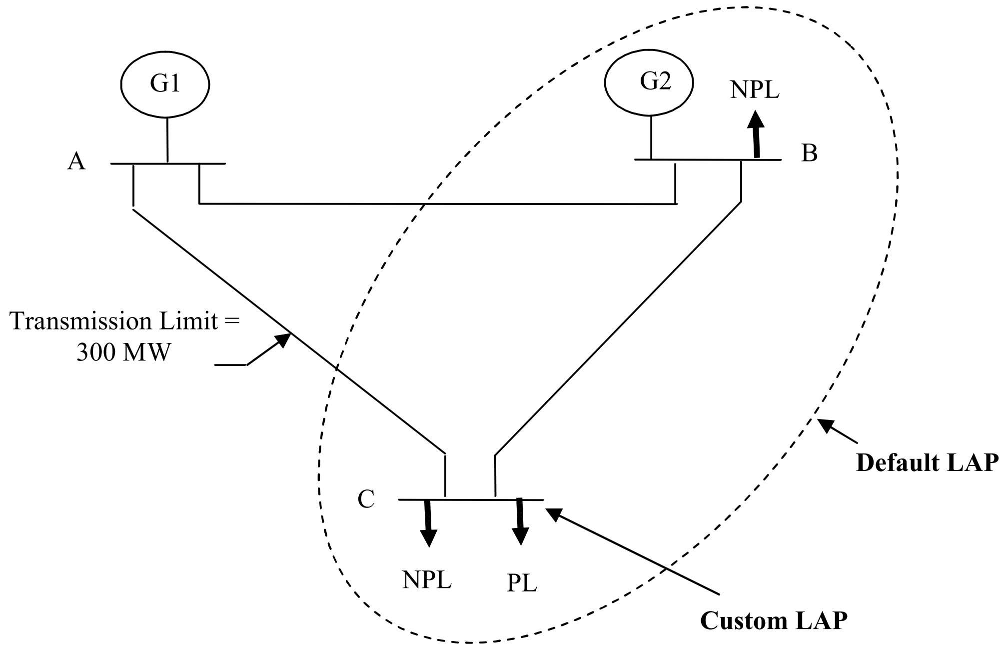

Figure 7 – Simple Three-Node Lossless Network

Line A-C has a maximum transmission capacity of 300 MW. For simplicity, transmission losses are ignored in this example.

The LAP Load Distribution Factors (excluding the PL) are $50% at node B and 50% at node C and the PL is 20% of the total LAP Load all located at node C, i.e., the Custom LAP consists of a single node with 100% of PL. To be more specific with a total load of 1,000 MW, we would have:

- NPL (B) = 400 MW
- NPL (C) = 400 MW
- PL (C) = 200 MW

Generators G1 and G2 each have Pmin = 0, Pmax = 1,000 MW, and their bids are:

- G1: $10/MWh for 0 ≤ G1 ≤ 1,000 MW, and
- G2: $50/MWh for 0 ≤ G2 ≤ 1,000 MW.

The NPL LAP day-ahead arbitrage price-quantity curve includes:

- 200 MW bid at $50/MWh and
- the rest of the NPL LAP load is vertical (price taker).

The PL bids as follows:

- 100 MW at $80/MWh and
- 100 MW at $120/MWh.

Note:

It is important to note the different treatment of the NPL and PL bids in the “Extended Non-Participating Load (Extended NPL)” functionality and the “Proxy Demand Resource (PDR)” functionality:

- The Extended NPL approach would use LAP load distribution factors of 50% at B and 50% at C along with a Custom LAP load consisting of one node (C) as shown in Figure 8.

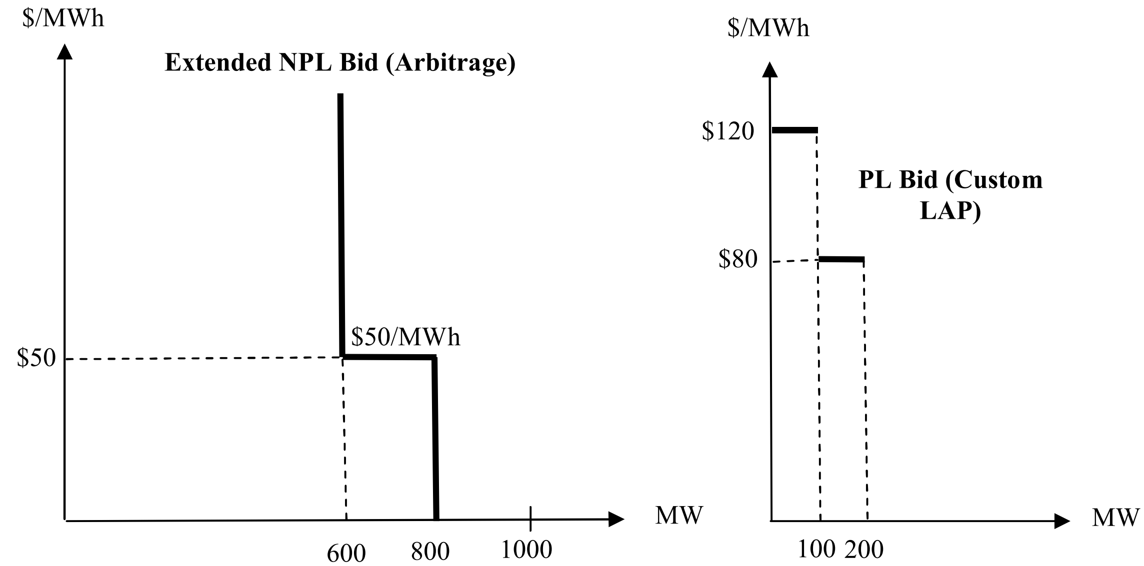

Figure 8 - Extended NPL Model for PL

- The PDR functionality would use LAP load distribution factors of 40% at B and 60% at C respectively, along with a 200 MW Proxy Generator at node (C) as shown in Figure 9.

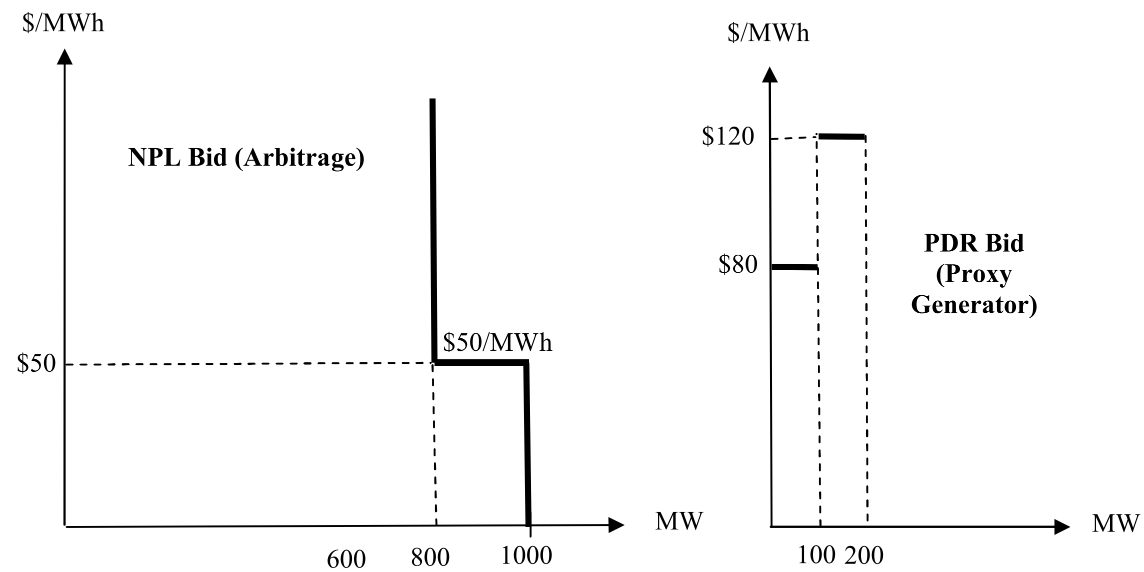

Figure 9 - PDR Model

Results for Extended Participating Load Model:

As explained above the Extended NPL model would involve 800 MW of NPL with LDFs of 50% at nodes B and C along with 200 MW of PL at node C. The least cost solution to serve all 800 MW of NPL and 200 MW of PL while respecting the 300 MW limit on line AC would be to generate 300 MW from G1 and 700 MW from G2. The resulting LMPs, would be LMP (A) = $10/MWh, LMP (B) = $50/MWh, and LMP (C) = $90/MWh and the LAP LMP would be 50%*$50 + 50%*$90 = $70/MWh. However, based on the bid curves in Figure 8, this would mean the LAP NPL would clear at 600 MW, and the PL would clear at 100 MW. The result would be a re-dispatch of G1 to 500 MW and G2 to 200 MW, but with no change in the LMPs. The solution in this case is thus:

- G1 = 500 MW
- G2 = 200 MW
- NPL (cleared) = 600 MW
- PL (cleared) = 100 MW
- LMP (A) = $10/MWh, LMP (B) = $50/MWh, LMP (C) = $90/MWh
- LAP LMPs: Default LAP LMP = $70/MWh; Custom LAP LMP = $90/MWh.
- Shadow Price of Line A-C Transmission Constraint: $120/MWh
- Settlement Results:
  - Payment by Loads: $70*600 + $90*100 = $51,000
  - Payment to Generators: $10*500 + $50*200 = $15,000
  - Congestion revenues (payment to CRRs): $120*300 = $36,000.
  - The difference between charges to loads and payments to generators = $51,000 - $15,000 = $36,000, which is the same as congestion revenues.

Results for the PDR Model:

As explained above the PDR model would involve 1,000 MW of NPL with LDFs of 40% and 60% at nodes B and C respectively, along with 200 MW of Pseudo Generation at node C. The least cost solution to serve all 1,000 MW of load without invoking the pseudo generator while respecting the 300 MW limit on line AC would be to generate 300 MW from G1 and 700 MW from G2, with the resulting LMPs: LMP (A) = $10/MWh, LMP (B) = $50/MWh, and LMP (C) = $90/MWh; but the LAP LMP in this case would be 40%*$50 + 60%*$90 = $74/MWh. However, based on the bid curves in Figure 9, this would mean the LAP NPL would clear at 800 MW, and the Pseudo generator would clear at 100 MW. The result would thus be a re-dispatch of G1 to 520 MW and G2 to 180 MW, but with no change in the LMPs. The solution in this case is thus:

- G1 = 520 MW
- G2 = 180 MW
- PDR (Proxy Generator): 100 MW
- NPL (cleared) = 800 MW
- LMPs: LMP (A) = $10/MWh, LMP (B) = $50/MWh, LMP (C) = $90/MWh, and Default LAP LMP = $74/MWh.
- Shadow Price of Line A-C Transmission Constraint: $120/MWh
- Settlement Results:
  - Net Load = 800 MW – 100 MW = 700 MW
  - Payment by Load: $74*700 = $51,800
  - Payment to Real Generators: $10*520 + $50*180 = $14,200
  - Congestion revenues (payment to CRRs): $120*300 = $36,000.
  - Difference between charges to loads and payments to real generators = $51,800 - $14,200 = $37,600 (different from congestion revenues).

Important Note:

The net collection by the ISO of $37,600 - $36,000 = $1,600 in the PDR model is due to the fact that the 100 MWs of pseudo-generator schedule is implicitly credited at the LAP price of $74/MWh instead of the nodal price of $90/MWh:

100*($90 - $74) = $1,600

This extra collection by the ISO would be included in the CRR Balancing Account.

In fact, in this example we ignored transmission losses. Otherwise, the PDR model would also create revenue non-neutrality for marginal loss surplus equal to the output of the pseudo-generator MWs times the difference between the marginal loss components of the pseudo-generator nodal LMP and the LAP LMP. This excess marginal loss surplus would be allocated to Measured Demand along with the rest of the day-ahead marginal loss surplus.

Example 5: Using Participating Load (Extended NPL) Model for Energy and AS

Consider simple three-node network of Figure 7. Assume the PL at node C consists of a number of DR resources collectively capable of providing 200 MW of PL Energy. Assume all 200 MW of these PL resources are registered to provide Non-spinning Reserve as well.

As explained earlier, the LSE SC for this aggregated set of resources must self schedule (as price taker) sufficient PL load in the Custom LAP under its load Resource ID to cover all of the Non-spinning Reserve MWs it intends to bid in the day-ahead market. In this example, if the DR Provider wishes to bid all 200 MW of Non-Spinning Reserve in the IFM, it would self schedule 200 MW of its DR resource as price taker in the Custom LAP.

Assume the LSE SC bids 200 MW of Non-spinning Reserve at $10/MW/h in the DAM. To cover this capacity, it self schedules 200 MW of PL as price taker in the day-ahead IFM.

Assume the LSE SC is also interested to arbitrage between day-ahead and real-time Default LAP prices, and submits its 800 MW of non-PL load (at the Default LAP) consisting of a price taker portion (600 MW) and a price sensitive portion (200 MW) similar to Example 4. The Default LAP and Custom LAP load bids are shown in Figure 10 below.

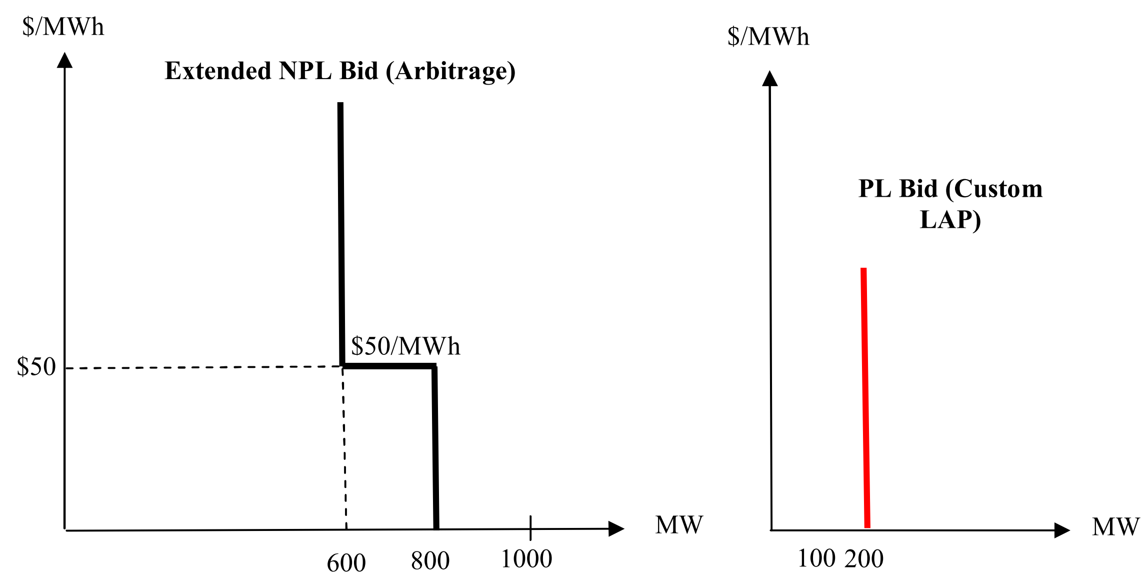

Figure 10 – Custom LAP Self Schedule to Cover 200 MW of AS

Assume the ASMP is $15/MW/h. So, the 200 MW of PL Non-spinning Reserve bid clear.

The IFM solution is as follows:

- G1 = 400 MW
- G2 = 400 MW
- NPL (cleared) = 600 MW
- PL Energy (self scheduled) = 200 MW
- PL Non-Spin (cleared) = 200 MW

- LMP (A) = $10/MWh, LMP (B) = $50/MWh, LMP (C) = $90/MWh
- LAP LMPs: Default LAP LMP = $70/MWh; Custom LAP LMP = $90/MWh.
- ASMP = $15/MW/h
- Shadow Price of Line A-C Transmission Constraint: $120/MWh
- Day-Ahead IFM Settlement Results:
    - Energy Payment by Loads: $70*600 + $90*200 = $60,000
    - Energy Payment to Generators: $10*400 + $50*400 = $24,000
    - Congestion revenues (payment to CRRs): $120*300 = $36,000.
    - Payment to the PL for AS: $15*200 = $3,000

Assume there are no changes in system conditions, demand, or bids in the real-time market, and there is no contingency in real-time, so the PL Non-Spinning Reserve Energy is not deployed (since it is contingency-only).

The real-time solution is thus:

- G1 = 300 MW
- G2 = 700 MW
- NPL (served) = 800 MW
- PL Energy (served) = 200 MW (self scheduled)
- PL Non-Spin Capacity (preserved) = 200 MW
- LMP (A) = $10/MWh, LMP (B) = $50/MWh, LMP (C) = $90/MWh
- LAP LMPs: Default LAP LMP = $70/MWh; Custom LAP LMP = $90/MWh.
- Real-time Energy Settlement Results:
    - Load Energy Deviation Charges:
        - NPL Load deviation: $70*(800 – 600) = $14,000
        - PL Load Deviation: $90*(200-200) = $0
        - Total Charge to loads: $14,000
    - Real-time Dispatch Energy Payment to Generators:
        - G1: $10*(300- 400) = -$1,000 (Charge)
        - G2: $50*(700 - 400) = $15,000 (Credit)
        - Total Net Payment to Generators: $14,000
    - Real-time Congestion Cost (Congestion Offset) = $0

Note: Comparing the results of Example 5 with Example 4, it appears that in Example 4, the PL provider saves $9,000 for not consuming 100 MW of its otherwise full demand, whereas in example 5, the PL entity foregoes this saving in return for $3,000 of Non-Spinning Reserve Revenue. This tradeoff is at the first glance not profitable for the PL provider. However, further scrutiny points out two main points:

- Assuming the PL Energy Bid price reflects the value of Energy for the consumer, the net PL saving in Example 4 is not $9,000, but ($90 - $80)*100 = $1,000. So in Example 5, bidding Non-Spinning Reserve results in $2,000 more net revenue for the PL entity compared to Example 4.
- Having said that, it does not necessarily follow that bidding Non-Spinning Reserve at any price is necessarily profitable for the PL provider. To see this, assume in Example 5, the AS bid price submitted were $1/MW/h, and the ASMP were $2/MW/h. The PL provider's AS revenue would have been $2*200 = $400, i.e., less than the $1,000. PL savings of Example 4. In fact, since the MRTU Release 1 PL functionality uses two different resources for PL Energy and PL AS bids, the

PL provider must internalize the opportunity cost of PL energy in its PL AS bid price. In this example, this would mean bidding AS at no lower price than the difference between the expected Custom LAP LMP and the PL Energy Bid price ($10/MW/h in this example). Such Energy/AS bid coordination on the part of the PL entity will not be needed under Dispatchable Demand Resource (DDR) in MAP, where the ASMP would include the lost opportunity cost of Energy.

Observations and Closing Remarks

MRTU Release 1 PL and NPL features and functions may be used effectively for DR Programs

The Proxy Demand Resource (PDR) Model:

- Provides useful enhancement for Energy-only DR programs
    - PDR makes it unnecessary to trigger DR before knowing IFM Results
    - PDR makes it unnecessary to provide forecasts separately for Default LAP and Custom LAP
- May result in some revenue non-neutrality (to be allocated to CRR Balancing Account and Marginal Loss Surplus)

The Release 1 PL Model (Extended NPL):

- Provides for DR Programs that offer Energy and AS
- The relationship between The load resource and pseudo-gen resources assigned to PL DR is considered only in settlement, not in market-clearing process
- The DR Provider bidding into CAISO Energy and AS markets must internalize any Energy opportunity costs in its AS bid (this need will be lifted in MAP, where DR PL Energy and AS bids are co-optimized)