



Stakeholder Comments Template

Energy Storage and Distributed Energy Resources Phase 4 – Work Shop

This template has been created for submission of stakeholder comments on the ESDER Phase 4 - Workshop that was held on June 27, 2019. The workshop, stakeholder meeting presentations, and other information related to this initiative may be found on the initiative webpage at:

http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResources.aspx

Upon completion of this template, please submit it to initiativecomments@caiso.com. Submissions are requested by close of business on **July 11, 2019**.

Submitted by	Organization	Date Submitted
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Please provide your organization’s comments on the following issues and questions.

PG&E’s comments on the NGR section can be summarized as follows:

1. Cycling costs should be included in the default energy bid (DEB) calculation as a component of the VOM/MMA adder, assuming the “deepest” level of discharge the NGR can achieve.
2. Alternatives to the DMM’s DEB proposal for NGRs should be explored; one potential approach is to use the prices and solutions generated from the Local Market Power Mitigation (LMPM) run itself to calculate cost-based DEBs.
3. State-of-charge (SOC) parameters should be prevented from manipulating DEB calculations just as they should be prevented from facilitating illegitimate BCR rents.

1. Default Energy Bids for Energy Storage

Please provide your organization's feedback on the ISO's presentation on the *default energy bids for energy storage* topic. Please explain your rationale and include examples if applicable.

PG&E would like to point out the inconsistency between CAISO's storage definitions and those used in the paper on cycling costs for lithium-ion storage resources. In order to be consistent, PG&E recommends that CAISO add a clear definition of "Cycle depth" to incorporate the concept of cycle depth into potential DEB calculations. This is a concern because under the current definitions, a lithium-ion battery discharging 10% of its SOC ten times (non-consecutively) over the course of a day will complete the same single full cycle as a lithium-ion battery discharging its full 100% continuously at its maximum ramp rate. But considering depth of discharge, the first battery will degrade less than the second. Thus, even though both batteries completed the same number of cycles, one is likely to have degraded more than the other due to cycle depth. Using this definition in reference to CAISO's example in the 6/27 Presentation (Slide 15), the black arrow line should represent one cycle at 40% cycle depth, as opposed to 0.4 cycles.

CAISO's proposal of adding a cell degradation cost curve into the DEB calculation would be difficult to implement, and it should not be the role of the marketplace to build such functionality. Battery operators and scheduling coordinators are in the best position to understand their cycling costs and therefore should maintain the ability to represent these costs in their bids. The only times at which cycling costs may not be protected are during periods of LMPM. Thus, PG&E recommends that cycling costs be included in the DEB calculation as a component of the VOM/MMA adder, assuming the "deepest" level of discharge the resource can achieve. This approach is simpler than implementing a dynamic VOM adder and ensures that battery operators are compensated for cycling costs during periods of mitigation.

Please provide your organization's feedback on DMM's presentation on *default energy bids for energy storage*.

PG&E offers the following comments in response to the DMM's proposal for NGR DEBs, which appears to be based on use of DEBs for all hours whether or not LMPM is active in all hours:

- It should be the role of scheduling coordinator to develop bidding strategies for NGR resources, not the marketplace (e.g. CAISO)

- The challenges of creating and implementing the robust Day Ahead price forecasting required for its profit maximization methodology are likely to be intractable, due to the interactions between bidding and pricing at constrained locations

PG&E proposes three alternatives to using a Day Ahead price forecast to calculate DEBs for NGRs:

1. Consistent with how DEBs are calculated for other energy-limited resources subject to energy-bid LMPM (i.e. hydro), use a longer-term price forecast applied to an extended future period (such as one month or one year) in calculating a model-based or negotiated DEB. The calculation would be agreed upon by the battery operator and CAISO in advance and the data would be adjusted on a tenor similar to Masterfile updates. DEBs for NGRs would not be modified in the Day Ahead timeframe unless an automatic scaling process was implemented, similar to the gas price multiplier used for natural gas resources.
2. Closely related to the first approach, but more transparent to both CAISO and the battery operator, apply historical price data to future periods. For example, a DEB that is calculated using the highest price an NGR charged at during the previous month would capture the daily price uncertainty faced by that resource. This approach has also been used by CAISO in the calculation of use-limited startup and minimum load costs.
3. A third approach would be to use the prices and solutions generated from the LMPM run itself to calculate cost-based DEBs. The attractive feature of this approach is that while mitigation periods are being identified, charging cost information from the LMPM solution can be used as inputs to the DEB calculation. In the simplest case, the DEB could be calculated based on the highest “unconstrained” (i.e. no SOC parameter, eligible for BCR) charging price generated by the LMPM solution, divided by charging efficiency and with a pre-calculated VOM/MMA adder applied. It’s entirely possible that when unconstrained charging occurs in the LMPM run, this calculation could be done as quickly as any other used in LMPM. However, when there is no charging (or only constrained charging) in the LMPM solution, strategic outcomes may arise. For example, battery operators may structure their charging bids to produce high charging prices for future DEB calculations. CAISO would be unable to mitigate this behavior except by reporting it to FERC.

Additional potential design requirements**Use of historical charging costs for market-based LMPM**

The proposed DMM methodology effectively imposes cost-based rates on batteries in both charging and discharging periods. Given that batteries are explicitly enabled to submit market-based bids, this approach is probably not appropriate for LMPM, which by definition (and per the BPM) can only affect bids in non-competitive discharge intervals.

In a new market-based LMPM paradigm, mitigation should be based on estimates of charging costs, both during the market horizon as well as for the available initial SOC, in order to ensure that a battery operates economically (i.e. recovers at least what it paid to charge up to the available SOC). This cost reflects the historic costs of charging, but may also be affected by the current day's discharges. While using default (historical) charging costs during a period of mitigated discharge is not ideal (i.e. they may not be high enough to capture a future discharge opportunity), these costs are readily available and likely less complex than forecasts of future charging costs or forecasts of discharge opportunities.

NGRs access to Bid Adder for Frequently Mitigated Units

PG&E recommends that CAISO allow NGRs to qualify as Frequently Mitigated Units under the Bid Adder Eligibility Criteria set forth in Tariff Section 39.8.1.

Prevent use of local market power during charging hours to achieve higher DEBs

As mentioned in the third approach towards DEB calculation, PG&E believes there is a risk of strategic behavior when a battery owner is charging during periods when other generating resources in its portfolio (batteries or otherwise) are using market power to set prices. Mitigation of this type of behavior should not be automatic, but subject to DMM review (and potentially, a FERC filing for cost-based rates). Faced with the risk of losing their ability to do market-based bidding, market participants/battery owners should avoid combining (or appearing to combine) supply-side market power with charging.

Prevent use of SOC targets to force uneconomic charging to achieve higher DEBs

SOC targets should be prevented from manipulating DEB calculations just as they should be prevented from facilitating illegitimate BCR rents.

Please provide your organization's feedback on SCE's presentation on *resource availability*.

PG&E and SCE agree that it is essential for NGR resources to recover their charging and VOM costs, especially during periods of LMPM. SCE also raises some important ideas regarding the vintage and technology type of the resource affecting the VOM and cycling costs.

2. NGR State-of-charge parameter

Please provide your organization's feedback on the ISO's presentation on *the NGR State-of-charge* topic. Please explain your rationale and include examples if applicable.

Please refer to the comments in the WPTF section below.

Please provide your organization's feedback on WPTF's presentation on *the NGR State-of-charge* topic.

PG&E generally supports WPTF's proposal for expanding CAISO's proposal from a single targeted SOC to a range (e.g. minimum and maximum end-of-hour SOC parameters). However, the various BCR scenarios emerging from this alternate proposal haven't been described in detail. PG&E recommends that CAISO consider all scenarios and account for them in their next straw proposal.

3. Variable Output Demand Response

Please provide your organization's feedback on the ISO's presentation on *the variable output demand response* topic. Please explain your rationale and include examples if applicable.

PG&E appreciates CAISO's efforts to address variable output demand response (VODR) from a planning perspective. PG&E supports CAISO's two key principles around VODR, namely,

- 1) The RA qualified capacity (QC) valuation for DR must consider the resources' reliability contribution to the system RA needs;
- 2) Market participation and must offer obligations (MOO) must align with VODR resource capabilities.

However, we differ in how the two principles should be met in practice. PG&E notes:

- CAISO's stated objective of moving to use the effective load carrying capability (ELCC) methodology to value the QC of DR is that it is a better planning tool for DR as it considers all hours rather than the availability assessment hours (AAH), which examine DR's contribution during the peak.
- For RA planning purposes, the Load Impact Protocol (LIP) is more rigorous than the ELCC in accounting for variability in RA output hourly, daily, and seasonally. The LIP also considers customer level performance and enrollment changes. Specific for daily operations, the LIP is capable of translating the QC into a realistic bid forecast, adjusting for weather and time-of-day.
- It is PG&E's assessment that the LIPs can accomplish the same tasks as the ELCC in a more rigorous manner. If the objective is to change the hours of evaluation, this should be undertaken in the RA proceeding and inform the LIP.
- PG&E would like to further understand CAISO's objectives with the proposal and the formula it suggests using for the ELCC.

PG&E further elaborates its position below.

As demand response is a function of customer load, its variability is driven by the underlying load. All DR is variable output to some degree. However, that does not mean DR resources are not capable of providing capacity beyond the peak hours (i.e., 4-9 p.m.) In fact, many DR resources are available for more hours outside of 4-9 p.m. Demand response has been viewed as a fixed-output resource available only for the RA measurement hours as a result of the RA planning process which prescribes DR to estimate its impacts for those hours on the monthly system peak days under 1-in-2 and 1-in-10 weather conditions. However, DR can be available for other hours as well. Another simplification is then made when the hourly impacts are condensed into an average hourly impact (a single MW value) across the measurement hours. That results in a misunderstanding that DR is fixed-output resource only available for the peak hours.

While PG&E supports CPUC Code 380 that requires each LSE to maintain physical generating capacity and DR adequate to meet its load requirements for all hours, PG&E is not convinced by CAISO's use of Code 380 as the rationale for favoring the

ELCC. We do not think applying ELCC to DR resources is a dramatic shift in the purpose of RA; it is only a different method. Instead, what we consider a dramatic shift is *the proposed change in the hour window DR resources are to be evaluated over for RA planning purposes*. CPUC Code 380 does not require the LSE to maintain DR to be available at all time to meet its load requirements. Rather, physical generating capacity and DR are considered together to ensure a LSE's load requirements are met at all times. The current RA planning assumptions only evaluate DR based on DR's reliability contribution to the grid for the peak hours, i.e., 4-9 p.m. If the CAISO would like the DR hours to expand, that ought to be done through the RA proceeding and adjusted in the LIP.

PG&E agrees that RA QC valuation and MOOs must be consistent, with the caveat that both should be determined under the same conditions or assumptions. QC valuation is based on the RA planning assumptions. If the weather conditions or the dispatch hours differ from the planning assumptions, it would be unfair to require DR to provide the same amount of capacity. In fact, even the ELCC cannot reconcile the discrepancy between QC and the forecasted output in the daily operations. The misalignment is not a result of an inferior method, but a difference in conditions between the planning scenario and daily operations.

To align QC valuation and MOOs, the underlying assumptions need to be consistent. The example on Page 45 of the CAISO presentation illustrates this point. Assuming maximum output means the QC valuation, the QC meets the CAISO need during the peak; however, the shortage of 5 MW occurs outside of the peak hours. Here, the shortage would be better characterized as an unrealistic expectation that the same QC would be available even for hours the QC is not estimated for. As a variable output resource, DR provides different capacity amount at different time. While it is reasonable that QC value is correlated to the MWs the CAISO expects to be available, the correlation should not mean equality given DR's variable nature. That is, we should expect the QC to be available once adjusted for time and other resource-specific factors (such as weather, for weather-sensitive resources).

The adjustment for time and other variables may seem a difficult challenge, but the information from the resource's ex ante impact evaluation would be able to facilitate the calculation. A capacity value can be estimated for each hour under different weather conditions. Consistency between planning and daily operations follows when the same regression model is used to estimate the QC and forecast bids.

In contrast, ELCC requires a nameplate capacity to generate hourly capacity values. The "maximum" output taken by CAISO, or Pmax, is not the true maximum capacity. Under the current construct, the Pmax is the average load impact estimated for the RA measurement hours. The LIP already represents the reliability contribution the resource is expected to provide for those hours and does not require a derating factor

to be applied on top. The same regression model can be used to estimate the load impacts for hours outside of the RA measurement hours and the load impacts do not require ELCC to be applied to it either. If the purpose of using ELCC is to generate hourly values for non-measurement hours based on the Pmax, then using the regression model for those non-measurement hours would be more accurate, taking resource-specific factors into account. Compared with the ex-ante impact evaluation model, the ELCC simply appears less rigorous, unable to considering as many variables the LIP is able to accommodate.

While PG&E is open to different methodology than the current construct, ELCC does not seem superior to the LIP. More critical than the methodology is the policy around hours of evaluation. The RA proceeding determines what planning assumptions or hours DR is to be evaluated over. PG&E looks forward to more discussion with the CAISO in support of its resource planning and grid operations.

4. Maximum Run Time Parameter for DR

Please provide your organization's feedback on the ISO's presentation on *the maximum run time parameter for DR* topic. Please explain your rationale and include examples if applicable.

PG&E supports CAISO's exploration of a maximum run time parameter in conjunction with minimum load costs. To inform the discussion, PG&E would like to share a few observations from its own DR portfolio. PG&E's current DR portfolio is entirely block dispatchable in one to six-hour blocks, limited by a four-hour run time, and is not discrete dispatchable. This is true for all programs regardless of end use load or retail tariff (e.g., Base Interruptible Program, Capacity Bidding Program or Smart AC). Accordingly, a resource that receives an award is notified to run for the duration of the dispatch award—and is not able to vary its output to unique dispatch targets at each market interval. With new program design at the CPUC this could change. In the interim, DR should be provided with the same treatment generators are granted and have their operating characteristics respected in the market (e.g., physical limitation like start up time, run time, etc.).