



Stakeholder Comments Template

Energy Storage and Distributed Energy Resources (ESDER) Phase 4

This template has been created for submission of stakeholder comments on the Straw Proposal for ESDER Phase 4. The paper, stakeholder meeting presentation, and all information related to this initiative is located on the [initiative webpage](#).

Submitted by	Organization	Date Submitted
<i>Michael Pezone</i> MAPZ@PGE.com (415) 973-6093	<i>Pacific Gas & Electric Company</i>	<i>5/17/19</i>

Upon completion of this template, please submit it to initiativecomments@caiso.com. Submissions are requested by close of business **May 17, 2019**.

Please provide your organization's general comments on the following issues and answers to specific requests.

PG&E believes that the priorities for this initiative should be:

- Creating an appropriate and fair bid mitigation paradigm for the non-generator resource (NGR) model
- Ensuring market rules do not create opportunities for strategic behavior
- Reflecting a demand response resource's capabilities in any forecast of capacity, at minimum, as granularly as the Load Impact Protocols (LIP).
- Enhancing the ability to represent operational characteristics of block dispatchable proxy demand response (PDR).
- If the objective is to allow behind-the-meter resources to provide regulation, enable the PDR model to provide regulation rather than allowing non-24x7 participation for NGR.

1. Non-Generator Resource (NGR) model SOC parameter

As a general principle, PG&E agrees that intervals for which a scheduling coordinator has specified a real-time (RT) SOC should not be eligible for bid cost recovery (BCR). There could be an exception to this - would the CAISO exceptionally dispatch a resource in the opposite direction of the desired SOC constraint? If so, it could make sense for the resource to be eligible for BCR since it is not being moved in the desired direction.

The CAISO indicated in the May 7th stakeholder call that it will create a list of rules regarding SOC constraints interacting with ancillary services. PG&E recommends that the CAISO publish these rules and/or include them in the working group materials. PG&E specifically requests clarification on the rules regarding BCR during contingency events. If a contingency event is called and the resource's stored energy is dispatched, the CAISO indicated on the call that the resource would be charged to meet future spin awards. If the resource is not eligible for BCR in this scenario, the resource could be unfairly penalized during high charging priced intervals. PG&E recommends that the resource be held neutral until it can economically charge, similar to PG&E's understanding of how regulation for batteries is treated today. The resource would not get no-pays and would continue to be eligible for its spin award.

Finally, while PG&E understands that the hourly SOC parameter will be RT and that the day-ahead (DA) SOC parameter will be end of day, PG&E could envision a scenario in the future where an hourly DA SOC parameter could be useful for Multi-Use Applications.

2. Bidding Requirements for energy storage resources

Given the amount of future storage expected in the CAISO market, PG&E fully supports the CAISO proposing market power mitigation. That being said, this topic is very complicated and requires further discussion. PG&E understands the CAISO's preference for option 1 for the Default Energy Bid (DEB), which mitigates to the highest 15-minute next day forecast price for half of the storage device's duration. PG&E has some caveats and questions on this approach, which may lead to adding elements of options 2 or 3. PG&E's key points and clarifying questions are listed below.

- How will the "expected real-time future prices" for the next day be calculated?
- How will the "expected real-time future prices" be calculated for each individual pNode?
- Given the difficulty of the forecasting task, PG&E proposes that the DEB be based on the higher of the pNode forecast per option 1 or a demonstrated charging cost, accounting for efficiency losses.
- The DEB should also account for a VOM/ MMA adder, which may be based on contract costs.
- How will the DEB be updated in RT for actual price conditions?

- Applying mitigation to a resource with charging and discharging is extremely complicated and will need to be thoroughly explored to avoid perverse outcomes.

PG&E would like additional details on how the next day 15-minute forecast will be developed. A single day forecast is likely to expose the CAISO to price risk and unexpected consequences. However, use of historical prices to calculate a forecast is also problematic. The approach used for CCE3 may work for a monthly or yearly calculation, but is not appropriate for a next day forecast because the given prices on a historic day would not be correlated to a particular future day, even corrected for gas prices. Would the CAISO use historical data? If so, over what period? How does the CAISO propose to take into account anticipated changes in conditions between the historical period to the future period? (These could include transmission availability, changes in fuel prices affecting LMPs, etc.).

If the CAISO mitigates discharge bids based on prices in an historical period, those prices may be lower than the prices that an astute trader may forecast based on current conditions. The battery may be drained before the anticipated peak prices lowering the returns. This would not be a problem for a conventional plant which should be willing to generate as long as the price covers its costs. The battery will not want to generate until it can sell its limited supply at near peak prices.

The use of some sort of average as a DEB basis may be appropriate if multipliers allow it to be high enough.

The CAISO examples have referenced the System Marginal Energy Cost (SMEC), which would not be appropriate for an individual resource. How would the CAISO forecast pNodes? The CAISO has proposed a locational gas adder in CCDEBE, but a locational gas adder may not be sufficient for locational electricity prices for storage.

PG&E has some strong concerns about how mitigation will impact the charging portion of the NGR curve and could lead to unforeseen and perverse outcomes. To maintain a monotonically increasing curve, the entire curve would have to be mitigated. However, this would lead to the outcome of forcing a battery not to charge when it wants to charge. There are some cases when a charging bid should not be mitigated because of a market power issue on the discharge side- this could actually create an outcome opposite of what is desired. Please see the *Appendix* for examples of problematic scenarios. PG&E would like all these scenarios, which are not limited, elaborated and addressed.

A storage resource may want to charge at relatively high prices if it anticipates higher prices will occur. It will want to hold the energy until near the high price levels. It is possible that the resource may charge at a high price and then have its discharge price mitigated based on much lower historical prices. It could be

discharged at a price lower than its charge price leading to a loss. This may lead to the need for a resource to have a DEB that is higher than the Option 1 calculation-similar to the right that generators have under CCDEBE to request higher DEBs. Mitigation may need to be based on the higher of the price forecast and the price at which the battery bought energy during its most recent charge cycle plus some adder for losses.

In addition, PG&E recommends using a VOM/MMA adder, including allowing for a contractual VOM/MMA adder, as some of the cycling costs will be driven by contractual arrangements. The CAISO should ensure that the VOM/MMA is not lithium specific and may need to account for additional parasitic losses that non-lithium technologies may have.

The CAISO indicated that the DA DEBs would also be used in RT. Will that capture the RT opportunity cost? How would the hourly scheduling period in DA affect the prices when considering prices over shorter periods in RT?

Finally, when a resource is mitigated for local market power, the duration is extended to the entire hour in which mitigation occurs. PG&E recommends that the CAISO change this treatment and mitigate only for the shortest duration (i.e. one interval) in real-time so as to not apply the DEB and discharge a resource when it is not needed to mitigate local conditions.

Appendix

The issues involved in performing demand side market power mitigation on NGR resources without other changes to Local Market Power Mitigation (LMPM) can be examined via the example provided by CAISO in its ESDER4 presentation, namely the mitigation of an NGR bid at \$150 from Pmin to Pmax. In all cases, the resource is assumed to be pivotal, and it is assumed that LMPM on the supply side requires mitigation.

Case 1: Entire bid is accessible to market

The resource being pivotal implies that supply is pivotal. There is no concept of “pivotal demand” in the CAISO market algorithms. Therefore, mitigation implies mitigation of bid on the supply segment(s): LMPM solution is discharging battery at some nonzero level. Bid is mitigated down to discharge level produced by LMPM.

Monotonicity of resource bid implies bid will be mitigated for levels below mitigated level in this case. (In the case of a single segment bid for generation, the bid would be mitigated from zero up, even though LMPM solution required mitigation only from a nonzero level.) However, it is conceptually incorrect to refer to the modification of the bid below the LMPM mitigation level as “mitigation of market power”: it is simply an effect of the way bids must be constructed for submission into the market.

Case 2: Supply bid is inaccessible to the market, for example due to state of charge management

The resource is deemed pivotal because LMPM doesn't recognize state of charge management. LMPM requires mitigation even though the only feasible schedule during the period would require charging, not discharging. Bid must be mitigated similarly to Case 1 for monotonicity of bid, but here the effect is quite different. The battery's charging bid is reduced (its willingness to charge is increased at a lower price) by effectively reducing the cost at which the battery is willing to charge. The possibility exists of a clearing price above the new bid price, and the resource would potentially receive bid cost recovery for the difference. In the case of the supply bid being inaccessible due to SOC management, the battery would not receive BCR. In the case of outage management, the battery might receive BCR. Additionally, the effect on the demand side is that the battery has successfully exercised market power to affect the cost of energy, with the assistance of CAISO's existing LMPM process.

Case 3: LMPM finds market power when the solution has the battery charging. This might be due to a market participant controlling multiple pivotal resources in a local area, or some other form of collusion/coordination among bids.

In this case, mitigation as currently performed would effectively increase the charging bid (i.e., making it less negative), making charging less likely. Such an outcome is not in PG&E's view within the scope of current supply side local market power mitigation, and any initiative to mitigate demand side market power should put all (participating) demand on an equal footing, rather than treating battery charging differently simply because of the required construction of its bid curve. Note that in the case of a \$150 bid for the entire bid range, the outcome of mitigation on the demand portion of the curve could turn a nearly "price taking" bid to charge into a bid to discharge, making management of charge through price more difficult.

3. DR operational characteristics

PG&E appreciates the CAISO's efforts to assist DR resources to better represent their resources when they are block dispatchable. PG&E believes a working group may be a worthwhile venue to address common standards for commitment costs and minimum load costs for DR resources, as described under options 1 and 2.

4. Variable output DR

- a) CAISO requests additional detail and reasoning from stakeholders who believe a more appropriate method exists for determining QC than applying an ELCC methodology.

- b) CAISO requests stakeholder feedback on controls needed to ensure that forecasts accurately reflect a resource's capability.

In response to the two questions above, PG&E is open to alternative approaches on how to forecast DR for CAISO's planning and operations. However, PG&E recommends that any new approach, at minimum, capture the same level of granularity as the Load Impact Protocols (LIP). There is a wealth of information from LIP studies that the CAISO forecast could use related to programs, location, and weather sensitivity. To that end, PG&E would like to continue the conversation on how the LIPs may be better utilized to inform the CAISO's operations and how the ELCC would apply to DR in light of the material differences between DR and other variable energy resources (VERs). PG&E recommends seeking clarity on the different approaches and raises the points below to further inform the discussion.

PG&E supports the CAISO's two principles regarding variable DR, including:

1. The qualifying capacity valuation methodology for DR resources must consider variable-output DR resources' reliability contribution to system resource adequacy needs.
2. Market participation and must offer obligations must align with variable-output DR resource capabilities.

However, PG&E notes certain statements in the CAISO Straw Proposal may reflect some misunderstandings about the LIPs or the ELCC methodology.

1. *"Variable-output demand response resources are those whose maximum output can vary."¹*

Unlike solar and wind resources, DR resources have no nameplate capacity and the maximum output is not always well-defined. One could argue the entire underlying customer load of a resource can be considered the technical maximum, although how much a DR resource can provide under "normal conditions" can be significantly less. Technically speaking, DR load impacts are a function of the underlying customer load and resource attributes (e.g., incentives) among other factors. When a maximum capacity is difficult to define, using a derating mechanism, such as the ELCC, would be problematic at the outset.

2. *"The current load impact protocols rely heavily on historical data from past demand response events, including test events. More importantly, the load impact protocols do not consider a resource's contribution in all hours and do not necessarily align with the loss of load expectation (LOLE) study performed by the CPUC for its ELCC calculations. The ELCC evaluates a*

¹ CAISO ESDER4 Straw Proposal page 18.

resource’s ability to reduce the LOLE, rather than evaluating a resource’s maximum load impact capability based on historic events that may or may not align with future system reliability needs.²

It is the merit of the load impact protocols that the ex-ante load impacts are grounded in historical data and adjusted for weather conditions of the system peaks. It is not correct to conclude that the load impact protocols evaluate a resource’s capability not aligning with future system needs.

More specifically, the ex-ante load impacts of a DR resource, which inform the RA availability assessment hours, are determined by two components:

1. Ex-ante per-customer impacts, which is a function of ex-post performance, adjusted for 1-in-2 (and 1-in-10) weather conditions of the monthly system peak;
2. Enrollment forecast.

As such, the load impact protocols are designed to estimate the DR resource’s capability at addressing system needs during the monthly system peak.

The ELCC assumes LOLE reliability target at 0.1 days per year, whereas DR’s weather conditions for RA assumes 1-in-2 weather. The target of 0.1 days per year is more comparable to the 1-in-10 (extreme) weather conditions. Had the load impact protocols taken a similar approach to the ELCC and assumed 1-in-10 weather conditions, the load impacts used to establish DR’s RA value would have been materially higher than what was adopted.

3. *“[T]he load impact protocols assess the load impact of an individual resource rather than the reliability contribution of a portfolio of variable resources.³”*

This statement is not correct. The ex-ante DR load impacts are available on both the program-specific basis (ignoring dual participation) and portfolio-adjusted basis (addressing dual participation). The portfolio-adjusted load impacts do represent the DR capability when the entire portfolio is dispatched simultaneously during the RA assessment hours. Since the load impacts are available by hour and do vary by weather conditions—contrary to a common misconception that DR impacts are only a single number for the whole month, the hourly load impacts already reflect a DR resource’s contribution to address system reliability needs during different hours. There is no need to apply the ELCC on top of the LIPs because LIPs already

² CAISO ESDER4 Straw Proposal page 21.

³ CAISO Straw Proposal page 21.

factors DR's contribution to system reliability during each of the RA assessment hours.

Nevertheless, the current ELCC methodology applies some blanket assumptions to the DR resource, overlooking resource-specific attributes. As a result, the DR capability is not estimated as accurately by ELCC as by the LIPs.

In conclusion, while PG&E is open to exploring alternatives to the current approach, PG&E is not convinced the ELCC is superior to the LIP methodology. In fact, the ELCC appears to be less accurate than the LIPs. PG&E believes the problem the CAISO is trying to solve is not from a planning perspective (RA), but the daily operations (i.e., the capability of DR on the daily basis). PG&E recommends the CAISO refer to the IOU proposal within the forthcoming Supply Side Working Group report, which proposes using the regressions in the DR load impact evaluations to inform the daily forecast. This way, the planning and the daily forecast are consistent in using the same set of estimates and same methodology.

5. Non-24x7 settlement of behind the meter NGR

PG&E appreciates the CAISO's questions to understand the implications of non-24x7 settlement for behind-the-meter (BTM) NGR. The proposal assumes that in some intervals the resource will be providing other services such as retail or distribution services.⁴ PG&E strongly recommends the CPUC and the CAISO coordinate on the issue as this scenario concerns a CPUC-jurisdictional BTM resource which therefore charges at a retail rate. Some of the CAISO's scenarios suggest the contrary—that a BTM resource could charge at wholesale.

In response to the three questions raised by the CAISO, today, neither jurisdictional clarity nor technical feasibility exists for LSEs to perform the given function. Currently, LSEs are unable to separate the service provided to inform load forecasting or differentiate wholesale versus retail for settlement purposes or to prevent bypassing retail rates. For the scenarios presented to be feasible the following changes would be needed which fall into the three below categories.

1. Rules & Standards

- UDCs and LSEs need jurisdictional clarity when a CPUC-jurisdictional BTM resource participates as an exporting resource in the CAISO market.⁵

2. Support Systems

- Separate metering to understand what is wholesale and what is retail

⁴ PG&E recommends CAISO clarify what their visibility requirements will be for BTM NGR resources which are: a.) providing A/S b.) turning over SOC management to CAISO c.) self-managing their SOC.

⁵ Stakeholders are expecting a rulemaking from the CPUC on Multiple Use Application implementation. It is unclear if this will be limited to energy storage or extend to all technologies.

- An accounting methodology for estimating retail versus wholesale in cases where the sub-meter is behind a retail meter and the resource provides different services in different intervals
 - IT systems and billing systems to support these new proposals
3. Operations and Communication
- Communication protocols or standards for DER providers to inform LSEs of their operating/MUA configuration for a given day/season to inform the LSE's load forecast

Considering the categories documented above would be necessary to enable non-24x7 participation and export, PG&E views a preferred path for BTM resources that wish to provide multiple services to be an enhanced demand response model. Using the demand response model solves many of the jurisdictional issues which have rules to prevent double compensation and prevents duplicating investments for a similar purpose.

As the CAISO considers a market model that would enable a retail BTM resource to provide a wholesale service it is worth reflecting that it took nine years of collaboration and stakeholder engagement to transition DR, as it was outlined in FERC Order 719, into a CAISO market product (i.e., PDR and RDRR). The careful and sometimes complex process required evaluating the existing rules and recognizing that new rules and systems were needed to solve retail and wholesale issues including: determining roles and responsibilities, avoiding double compensation, establishing data sharing procedures, developing customer privacy rules, and developing IT infrastructure, systems, and processes. A similar undertaking will be needed to enable a retail customer to participate in wholesale markets and export if non-24x7 participation is allowed. PG&E is concerned that this could result in duplicated efforts and investments if DR is to accomplish the same outcome.

Demand response is evolving to accommodate the changing physical and operational characteristics of DER aggregations. New models of DR are being developed to respond to this diversity in capabilities with proposals for bi-directional products and new baselines to enable more frequent dispatch. New DR models also address the core concern that seems to be driving the non-24x7 request. CESA includes the ability to provide regulation as one service and also flags that it does not have to be NGR, but could also be through PDR.⁶ PG&E recommends rather than enable non-24x7 participation for NGR, that enhancing the PDR model to provide regulation be included in the scope of ESDER 4.

To respond to the CAISO's specific questions:

⁶ CESA comments April 1, 2019. Page 2. 'This path may be through both Proxy-Demand Resource (PDR) modifications and or through enhancements to the DERP model to render it more viable for use by Distributed Energy Resources (DERs) in multi-use configurations, e.g. removing the 24x7 participation requirement.' <https://www.aiso.com/Documents/CESAComments-EnergyStorage-DistributedEnergyResourcesPhase4WorkingGroup-Mar18-2019.pdf>

- a) *As a behind the meter resource under the non-generator resource model, any wholesale market activity will affect the load forecast. How will load serving entities account for changes to their load forecast and scheduling due to real time market participation of behind the meter resources?*

Currently there is not a way for an LSE to account for changes due to resources that want to provide multiple services such as alternating between retail, wholesale, and distribution services. For an LSE to account for such changes, visibility and communication would be needed. Ideally, DER operations would be persistent in such a way that the load forecast could adapt to the changing load profiles of resource operations. However, this assumes that changes would be consistent enough for forecasters to plan for this change. It may be premature to assume the resource will have a fixed operational profile if it can provide multiple services and is able to arbitrage between providing services. Alternatively, the approach could be that the DER communicates its operational forecast to the LSE, so the LSE can account for this change when it forecasts load. This type of communication would require standardization, as well as, IT systems to support such communication. There is a risk that if an LSE cannot predict the DER behavior that an LSE could be submitting a forecast that over or under procures for its load.

- b) *How would a utility distribution company prevent settling a resource at the retail rate when the behind-the-meter device is participating in the wholesale market?*

Today an LSE does not have the visibility, IT systems or rules in place from the CPUC and the CAISO to prevent settling a BTM resource at the retail rate if it is participating in the wholesale market.

- c) *If a behind-the-meter resource is settled only for wholesale market activity, what would prevent a resource from charging at a wholesale rate and discharging to provide retail or non-wholesale services? How would this accounting work?*

Today an LSE does not have the visibility, IT systems, billing systems, or the appropriate accounting methodology to differentiate wholesale from retail service. Bypassing retail rates would be possible.

For example, if we have a 100kW battery storage resource which is at a 0% SOC which:

- i. Charges 50 kW at \$15/MWh at 1AM and again charges 50kW at \$0.50/MWh at 2PM.

- ii. Discharges 60 kW for retail bill management at 7PM and discharges 10kW at 8PM in response to a wholesale market signal.

The LSE would need to be able to then engage in an exercise to assess what electrons were used for which service. In this example, when the battery storage resource discharges 60kW for retail purposes, and the battery charged at wholesale in two separate intervals, what charging rate should be applied for the 60kW? What this question raises more generally is that when a resource charges at wholesale and later does not provide a wholesale service—today, neither the rules nor IT or billing systems are in place to calculate how the electrons that charged the battery at wholesale were later used.

6. Additional comments

Please offer any other feedback your organization would like to provide from the topics discussed during the working group meeting.

To follow up on previous comments made by PG&E and not addressed by the CAISO to date, PG&E urges the CAISO to update its tariff to reflect a minimum bidding size requirement of 100kW and work with the CPUC on developing reliability requirements for under 1MW. Further details are provided below:

- **The CAISO should update its tariff to reflect a minimum bidding size requirement of 100kW for PDR.**
PG&E urges the CAISO to update its tariff to reflect a minimum bidding size for PDR of 100kW. The CAISO's tariff, Section 4.13.5.2.1 (pg. 102), states, "The minimum Load curtailment of a Proxy Demand Resource shall be no smaller than 0.1 MW." PG&E has interpreted this to mean all resources must bid at least 100kW. However, PG&E recently learned that the CAISO's minimum size requirement is interpreted by the CAISO's legal department as the capacity size requirement not a bidding requirement. This policy is leading to resources that are at minimum 10kW being bid and dispatched into the market.
- **For resources under 1MW, the CAISO should coordinate with the CPUC in developing reliability requirements.**
Currently the only enforcement mechanism for the Demand Response Auction Mechanism (DRAM) to ensure that a resource is meeting its must offer obligation (MOO) is that a resource is subject to RAIM. However, this does not apply to resources under 1 MW. Most distributed energy resources (DERs) participating in the wholesale market are under 1 MW. Moving forward, as the number of DERs under 1 MW grow and provide reliability services, PG&E recommends the CAISO coordinate with the CPUC in developing reliability performance requirements.