2020 Distribution Investment Deferral Framework ​​  
Request for Offers ​(2020 DIDF RFO) PowerAdvocate Bidder

Questions & Answers

1. Question 1

**Q1A**: For the Saugus-Newhall project, the traditional deferral would be to rebuild 5mi of 66kV between Saugus and Newhall substations. However, the DER targets for this project (slide 30 of webinar) are prescribed to be at or downstream of the following 16kV circuits: Calgrove, Cross, Dewitt, Gavin, Lyons, Mcbean, Mentry, Neargate, Powell, Wildwood, Wiley. Does this mean DER solutions at the 66kV Saugus sub, 66kV Newhall sub, or either Saugus-Newhall 66kV circuit are ineligible?  
  
**A1A:** Technically, DER solutions at neighboring substations other than Newhall substation would be eligible. However, the DER operational requirements, DER MW and MWh needs would be different than the original identified needs at Newhall. This is due to line losses on the networked subtransmission system and would require a new simulation to determine the load reduction needed at a neighboring substation. In addition, we do not allow solutions to connect directly to the substation, per SCE's standards. This would require a termination point (customer switch gear) outside the substation and would require an open position on the bus at the substation. That position will have a line that will build to a customer switchgear. Developers can build their own line from that gear to wherever they want, granted they acquire their own easements and right of way for their line. Another significant point to be known is if a customer requests this configuration, the line SCE would build from the sub to the switch will be subject to SCE use for other customers when the need arises in the future--it won’t be dedicated permanently. Currently, there are no open positions on the bus at Saugus or Newhall substations. The cost of extending the bus, the circuit breaker, and building out a new line position will fall on the developer. The Saugus-Newhall 66kV line is the overloaded line during an outage contingency scenario, and thus would not be eligible as an interconnection point because the DER would contribute to the overloaded asset before load is consumed. In addition, since this project is under an outage contingency scenario, there is no definitive way to predict which line would have an outage to install DER on the parallel line. This would result in calling for a solution to install DER on both parallel lines, which would not be cost-effective.

**Q1B:** For the Elizabeth Lake projects, the traditional deferral would be to rebuild 3mi of 66kV near the Elizabeth Lake substation. However, the DER targets for this project (slide 51 of webinar) are prescribed to be at or downstream of the following 16kV circuits: Cello, Clarinet, Guitar, Oboe, Tambourine, Trumpet, Tuba. Does this mean DER solutions at the Elizabeth Lake 66kV sub or at either of the Elizabeth Lake 66kV circuits planned for deferral are ineligible?

**A1B:** Technically, DER solutions at Elizabeth Lake substation would be eligible. In addition, we do not allow solutions to connect directly to the substation, per SCE's standards. This would require a termination point (customer switch gear) outside the substation and would require an open position on the bus at the substation. That position will have a line that will build to a customer switchgear. Developers can build their own line from that gear to wherever they want, granted they acquire their own easements and right of way for their line. Another significant point to be known is if a customer requests this configuration, the line SCE would build from the sub to the switch will be subject to SCE use for other customers when the need arises in the future--it won’t be dedicated permanently. Currently, there are no open positions on the bus at Elizabeth Lake substation. The cost of extending the bus, the circuit breaker, and building out a new line position will fall on the developer. The two 66kV subtransmission lines to Elizabeth Lake are the overloaded lines during an outage contingency scenario, and thus would not be eligible as an interconnection point because the DER would contribute to the overloaded asset before load is consumed. In addition, since this project is under an outage contingency scenario, there is no definitive way to predict which line would have an outage to install DER on the parallel line. This would result in calling for a solution to install DER on both parallel lines, which would not be cost-effective.

1. Question 2

**Q2:** On webinar slide 28 regarding Crossley 33kV locations that meet the deferral need, I note there are NO locations along the circuit which are ineligible for siting a DER (i.e. red sections).   
I would like to confirm that a bidder could propose a DER located very close to the Eisenhower substation, but instead of POI being the substation, the POI is the Crossley 33kV circuit near the substation.

**A2:** Yes, a bidder could propose a DER located very close to the Eisenhower substation on the Crossley 33kV circuit. There are no locations where DER would not meet the distribution need on the circuit.

1. Question 3

**Q3A:** Per SCE's advice Letter to the PUC dated 11/15/2019, could SCE please confirm the primary metric(s) that will be used to evaluate the cost-effectiveness of deferral proposals? Specifically, will it be (1) the cost of the "traditional mitigation" for each project, (2) the annual LBNA value for each year of the need for each project (e.g. 6-7 years), or (3) some other metric or combination of metrics?

**A3A:** The NPV of each DER portfolio which meets the distribution need will be compared against the traditional solution’s deferral value to measure the portfolio’s cost-competitiveness. During the initial screening of projects (GNA/DDOR), LNBA is used to approximate the deferral value of the traditional solution. During the Offer valuation and selection process, the deferral value is calculated per the traditional solution's execution details to improve the accuracy of the deferral value measurement. Both LNBA and the deferral value use the real economic carry charge (RECC) method.

**Q3B:** SCE's RFO states that the energy, RA and ancillary services value of the proposed solutions will be evaluated in addition to the deferral value. For BTM projects, SCE will consider "load reduction as equivalent to RA capacity for valuation and selection purposes" and "energy benefits will be based on the validated energy reduction estimates contained in the Offer (i.e. avoided energy costs)" (p. 14). Will these valuations be subject to reduction and/or disqualification based on incrementality concepts for BTM projects participating in NEM and/or SGIP?

**A3B:** There will be no automatic value deduction based on the offer’s incrementality classification. During complete and conforming process, SCE will engage in discussions with the sellers to understand the offer’s characteristics to determine its incremental capacity or energy. We encourage you to reach out to us ahead of time to discuss your project (before submitting the bid) to help us understand incrementality implications (if any) to your offer.

1. Question 4

**Q4A:** To summarize, DERs on either Saugus-Newhall 66kV #1 or Saugus-Newhall 66kV #2 circuits are not allowed. DER into the Newhall 66/16kV substation directly (new circuit, taking into consideration substation jurisdiction and bus expansion) is allowed. DER into the Saugus 220/66kV substation directly is allowed. Do I have all that correct?

**A4A:** DER on Saugus-Newhall 66 kV #1 or Saugus-Newhall 66 kV #2 are NOT allowed. DER into the Newhall 66/16 kV substation is allowed. DER into the Saugus 220/66 kV substation is NOT allowed, but DER into the Saugus 66/16 kV substation is allowed.

**Q4B:** To summarize, DERs on either Elizabeth Lake 66kV #1 or #2 are not allowed. However, DER into the Elizabeth Lake 66/16kV substation directly is allowed. Do I have all that correct?

**A4B:** DERs on either Elizabeth Lake 66 kV #1 or #2 are NOT allowed. DER into the Elizabeth Lake 66/16 kV substation is allowed.

1. Question 5

**Q5:** After our review of the bid documents, we wanted to clarify FCDS/RA for the IFOM ES product. It is clear that SCE is requesting RA only or RA with Put contract types for the IFOM ES product, both of which require FCDS.  
  
PER MUA guidelines, how can the IFOM ES provide SCE with both RA as well as distribution deferral?   
  
In Part II of the Technology Neutral Pro-Forma, the notes indicate that initially none of the Product should be allocated toward distribution needs and all to RA needs. Can you please clarify as this seems counter to the purpose of the RFO?  
  
There is a note in the Technology Neutral Pro-Forma in italicized green under the Table of Contents that says:  
"Additionally, to the extent that Seller seeks to sell only distribution deferral capacity while retaining Resource Adequacy capacity or some other portion of the Product, Seller should contact SCE during the bidding phase of the RFO."  
  
If Dimension wished to submit a bid alternate/variation for distribution deferral capacity only, how should we do that?

**A5:** Yes, both RA only and RA with Put will require IFOM ES projects to have FCDS. Per current MUA guidelines, SCE will receive RA capacity for all months except for months where a distribution deferral event/LRCD occurs. Article 1.03 (c) of the attachments to the TNPF provides clarification to reductions of the 'Product' due to LRCD Dispatch which address your questions regarding how the contract handles RA vs. distribution needs. SCE encourages you to submit different variations of offers. If you desire to provide offer(s) just for distribution deferral capacity only you can state those variations in your Seller Proposal Letter.

1. Question 6

**Q6:** It seems there are two ways to address the deferral MW and MWh needs identified in the projects. I would like to confirm each way is acceptable to SCE with respect to conforming offers.

Taking the Crossley/Eisenhower deferral as a simple example, this need is 2.5MW and 4.4MWh.

* 1. Approach #1 is to offer a DER that is 2.5MW/2.5NQC/10MWh.
  2. Approach #2 is to offer a DER that is 2.5MW/1.1NQC/4.4MWh.

Approach #1 will be more RA quantities, however higher capital costs.

Approach #2 will be less RA quantities, however lower capital costs.

Are both approaches acceptable to SCE?

**A6:** Both ways are acceptable.  
  
SCE encourages these sorts of bid permutations as it provides us with the opportunity to select the optimally sized project for both the deferral need as well as RA.

1. Question 7

**Q7:** Our team is actively evaluating Standalone BTM Storage configurations and are wondering if new assets, constructed for the purpose of this RFO, are permitted to participate in any of SCE's DR programs while also providing the required services to SCE (assuming no scheduling conflicts). If so, would participating in these programs, in addition to the RFO obligations, trigger any effect on a projects incrementality (i.e. a capacity reduction) and/or how SCE would assess the bid?  
  
Essentially, we would like to clarify what bullet #10 on page 24 of the RFO instructions states (i.e. no benefits are to be obtained under the SCE ADRP) - does this also include SLRP?

**A7:** This type of offer would be considered “partially incremental” since it intends to utilize other incentives and possibly “not incremental” if there could be potential conflicts with the distribution deferral requirements. These items would be considerations during the offer evaluation and selection process. SCE encourages bidders to consider submitting both Wholly Incremental and Partially Incremental offers while proposing project(s) that prioritize distribution deferral services.  
  
If there is a desire to discuss more specific offer(s), please let us know and we can have a call to discuss.