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Subject: R.14-08-013: CESA's 2019 DPAG Meeting Feedback

Re: CESA's survey responses on IOUs' 2019 Distribution Planning Advisory Group (DPAG) meetings

Dear DPAG stakeholders:

Thank you for the opportunity to share our feedback on the Grid Needs Assessment (GNA) filing, Distribution Deferral Opportunity Report (DDOR) filing, and Distribution Planning Advisory Group (DPAG) meeting presentations. These filings and meeting materials have been helpful for stakeholders like CESA to better understand each investor-owned utility's (IOU) distribution planning processes and whether and how planned investments for distribution capacity, reliability back-tie, microgrid resiliency, and voltage support services can be deferred by distributed energy resource (DER) alternatives. Our specific feedback for each IOU is detailed below:

<u>Pacific Gas and Electric Company (PG&E)</u>

1. **What feedback do you have regarding the candidate projects that PG&E proposed for solicitation?**

CESA supports PG&E's recommendation to move forward with three Tier 1 projects, as these three projects (Alpaugh New Feeder, Calfax Bank 2, Santa Nella New Bank/Feeder) seek distribution capacity dispatched on a day-ahead basis, which has proven to be a well-suited application for DERs. The LNBA values are moderate, but these projects strike the right balance of being achievable for deferral. Given the three-year-ahead timeframe, it is worthwhile to move these projects to an RFO.

The Alpaugh New Feeder, Calfax Bank 2, and some downstream needs of the Santa Nella New Bank/Feeder projects were identified as having longer-duration overloads of 7 to 16 hours.

Certainly, there are long-duration storage technologies that should be able to compete to deliver on these long-duration needs, but, as PG&E has done in the past, CESA recommends that PG&E continue to create partial delivery windows such that a portfolio of shorter-duration DERs to meet the full need. In doing so, PG&E will invite greater market participation in the RFO.

2. **What feedback do you have regarding the candidate projects that PG&E did not propose for solicitation?**

CESA has no additional feedback on the candidate projects at this time. Pending additional information on back-tie service requirements (as detailed in our response to Question 5), CESA tentatively supports PG&E's proposed tiering of projects. However, if the 24-hour service requirement is not substantiated for the Tier 2 and 3 projects, particularly for the Camp Evers 2107 and FMC 1102 projects, CESA believes that these projects could be considered for Tier 1 status. Even with the real-time requirements, the Camp Evers 2107 and FMC 1102 projects have such low overcapacity percentages (3%-4%) that DERs such as energy storage could feasibly reserve capacity for this back-tie requirement while using the rest of its capacity for other services. Pursuant to the Multiple-Use Application (MUA) rules, such capacity-differentiated services represent a smart and possibly cost-effective means to deploy and operate energy storage to deliver great ratepayer value. Furthermore, these two projects generally rate favorably across the other prioritization metrics, especially around LNBA value and number of customers driving the need – the latter of which demonstrates a large opportunity for BTM resource deployment as well as stronger forecast certainty.

CESA also supports the continued monitoring of the Estrella Substation project, which represents a high-dollar and high overload project. CESA understands that this substation is intended to provide both distribution capacity and reliability back-tie services. Given the potential for lower-cost DER alternatives, PG&E should provide more detail on whether and how these service requirements could be decoupled.

3. **What feedback (if any) do you have on PG&E's DPAG meeting(s) to date?**

CESA appreciates the well-run and informative DPAG meeting that PG&E and the IPE have prepared. For this cycle, CESA recommends that the DPAG stakeholders aim to seek informal consensus through these meetings to minimize the need to submit protests to PG&E's advice letter filing on November 15, 2019. While consensus may not always be achieved, CESA hopes that stakeholders can work together in these DPAG meetings to come to a general agreement on the candidate deferral projects to be submitted for an RFO in order to minimize regulatory approval delay. Last year, the launch of the DIDF RFO was delayed due to staff review needed because of stakeholder protests, but if possible and ideally, the IOUs, IPE, and stakeholders would achieve this consensus to ensure a timely launch of the RFO in January, at the latest.

4. **What additional information do you need, if any, to determine feasibility of bidding on a project in the 2019 DIDF RFO cycle?**

CESA has no requests for additional information at this time. CESA appreciates the load curves and equipment rating limits provided for each circuit/feeder, as done at the DPAG meeting. Similarly, as done for the Calfax Bank 2 project, CESA appreciates PG&E providing any charging constrained locations for the candidate projects. Any information on charging constraints is helpful, if there are any for other project locations.

5. **What questions or comments do you have for the Independent Professional Engineer regarding his presentation and review of PGE's GNA/DDOR and candidate deferral prioritization process?**

CESA seeks to understand the reliability (back-tie) service requirements, which PG&E defined as requiring 24 hours of fast reconnection and availability of excess reserves under an n-1 contingency scenario. However, CESA is unclear on whether back-tie service must be subject to a 24-hour requirement. While CESA understands that five-minute real-time dispatch is needed given the unplanned nature of outages from distribution infrastructure elements, it is not clear why such back-tie must be provided across a 24-hour basis. CESA requests that PG&E provide additional information on the average or other trend data on the duration of these outage and fault conditions, which necessitate back-tie services (*e.g.*, via back-tie switches), and that the IPE seek and validate this additional information. This information is not provided in either their GNA or DDOR filings and was discussed to some degree at the September 19, 2019 DPAG meeting. As PG&E noted, baseload needs are not suitable for deferral by DERs, so substantiating this service requirement will be important to understand whether DERs can provide back-tie services at all, or only in certain circumstances where back-tie is only required on a more time-limited basis. Ultimately, CESA seeks to understand whether it is appropriate to set a blanket 24-hour requirement for back-tie services, or whether a project-specific assessment on the duration of back-tie service should be established.

Furthermore, CESA seeks to better understand why certain candidate deferrals required islanding in addition to real-time back-tie service. This information was not provided in the GNA or DDOR filings and was inadequately covered in the DPAG meetings. CESA also requests further information on how islanding capabilities would be established as service requirements for DERs.

Lastly, questions were raised on whether the Estrella Substation could have its capacity and reliability back-tie service needs decoupled such that DERs could more feasibly address the distribution capacity need. Since the in-service date of this project is not until 2024, it may be worthwhile to dedicate some time in the upcoming DPAG meetings to discuss this high-cost project in order to exhaust potential DER alternative options.

6. **Any additional questions or comments for PG&E?**

For future DPAG meetings, though it does not have to be this 2019 DIDF cycle, CESA would like to explore with PG&E, IPE, and the Commission on whether resiliency (microgrid) needs are best addressed through the DIDF process. The DIDF only looks at planned capital investments that could be deferred by DERs, but the DIDF may limit the assessment of DERs to the relative economic value of the non-wires alternative relative to capital "wires" investments, such that DERs may not fare as well within this framework. For example, there may be additional benefits of DERs in offsetting onsite diesel consumption that would not be accounted for in the head-to-head comparison. Additionally, if microgrid investments were to be included in the DIDF, CESA seeks to understand whether the utility investment would entail not only distribution capital investments but also generation resources, which may be needed for microgrid configurations. As explained in its GNA, for example, PG&E described how it will build pre-installed interconnection hubs to allow for safe and rapid connection of temporary generation in its Resiliency Zones. Furthermore, the planning standards for "need" of microgrids do not appear to be established, according to CESA's understanding, such that the DIDF may never really capture opportunities for DERs to provide microgrid (resiliency) services. Any insights from PG&E's pilots or Resiliency Zones concept would be helpful in future DPAG meetings, if not the current-year ones.

CESA appreciates PG&E's discussion of lessons learned at the DPAG meeting and how it has applied them to this cycle. CESA agrees with the lessons identified but requests some minor terminology suggestion to say that DERs cannot or may struggle to meet "baseload" needs but should not be screened out for being unable to meet "long-duration" needs, which are distinct and should be classified differently. Fewer technologies are able to provide 8-12 hours of duration, but such long-duration needs are still addressable by current and emerging technologies, such as flow batteries, compressed air storage, etc.

<u>**Southern California Edison Company (SCE)**</u>

1. **What feedback do you have regarding both the number and characteristics of the Tier 1 candidate projects SCE proposed for solicitation?**

CESA supports and agrees with SCE's recommendation to move forward with the four Tier 1 projects. The top three projects (Eisenhower 115/33 kV Substation, Saugus-Newhall Subtransmission Line, Pechanga 115/12 kV Substation) each represent strong candidate projects with ideal duration of need for DERs (2-6 hours) and favorable LNBA value, though they represent projects with moderate forecast uncertainty given that their in-service date requirement is in Year 4 of the planning horizon (June 1, 2022). Particularly, SCE should be commended for proposing a test case for DERs to meet a subtransmission reliability service need for the Saugus-Newhall Subtransmission Line project.

CESA also recommends that the Alessandro 115/12 kV Substation project remain in Tier 1 given that it rates favorably in the cost-effectiveness metrics, even though it may be more challenging to meet given the multiple circuit needs and the longer forecasted need date. The uncertainty of a need in 2023 can be mitigated through contingency planning and contracting that allows SCE to make modifications to the MW need. Even though industry favors certainty of the need, the actual MW of the contract can be finalized in 2020 once updated forecasted numbers are provided.

2. **What feedback do you have regarding the candidate projects SCE did not propose for solicitation? In particular, based on the discussion and metrics presented at the meeting, do you think the two Saugus subtransmission projects ranked in Tier 2 are good candidates for bidding by the developer community and should be moved to Tier 1?**

CESA generally supports SCE's recommendations to not advance the Tier 2 projects for bidding in an RFO with two exceptions. Though SCE seeks to 'test' DER solicitations for sub-transmission reliability needs for one project (*i.e.*, Saugus-Newhall) since SCE has only successfully solicited for distribution capacity needs to date, CESA sees a major value-stacking opportunity for DERs to be solicited for two Tier 2 projects (discussed below) to address not only the sub-transmission reliability need but also to address the System Resource Adequacy (RA) needs as identified in the Integrated Resources Planning (IRP) proceeding (R.16-02-007), where the Commission has an active Proposed Decision that would direct SCE to procure 1,745 MW of System RA capacity between 2021-2023. With the multiple-use application (MUA) rules in place (as adopted in D.18-01-003) and SCE seeking DERs that can provide both distribution service value as well as RA capacity (per their technology-neutral *pro forma* contracts), CESA sees tremendous ratepayer value that could be delivered from DER providers that can cost-effectively address both urgent needs.

For the Saugus-Elizabeth Lake-MWD Foothill Subtransmission Line project (referred to hereafter as "Saugus-Elizabeth"), CESA recommends that SCE move this project into Tier 1 and advance it to the 2020 DIDF RFO. The need is defined as experiencing minimal summer overload in 2023 and 3.88 MW summer overload starting in 2024, when the need for DERs is greatest and growing. The duration of the need starting in 2024 and beyond ranges between HE14 and HE19, which represents a manageable 4-5 hour duration of need that can be readily addressed by a range of DERs. The need overlaps to a degree with the RA availability assessment hours (AAH) between 4pm (HE16) and 9pm (HE21), which represents the critical peak demand periods when RA is needed most, though CESA recognizes that RA resources have a must-offer obligation to make their capacity available to the market across all hours of the day. Furthermore, the CAISO has highlighted "operational" RA deficiencies between HE18 and HE20 when assessing the RA stack on an hour-by-hour basis. Taken together, CESA sees potential for resources procured in the 2019 DIDF RFO to serve complementary, though somewhat overlapping, needs related to System RA capacity. To support the case for Saugus-Elizabeth in Tier 1, DERs can be sited at one location downstream from this substation to address the need, making it simpler and more likely for DER deferral success – *i.e.*, not having to rely on multiple circuit needs to be met from a portfolio of DERs from one or more counterparties. The maximum 10-year capacity need is also not too large and is achievable (6.8 MW).

For the Saugus-Colossus-Lockheed-Pitchgen 66 kV Subtransmission Line project (referred to hereafter as "Saugus-Colossus"), CESA recommends that SCE also move this project into Tier 1 and advance it to the 2020 DIDF RFO. The case for this project is similar to that for the Saugus-Elizabeth project in that the need can be addressed by DERs sited at one location, in addition to the duration of need being manageable (around 2 hours in 2023 and 4-5 hours in 2024 and beyond). The maximum 10-year capacity need is also not too large and is achievable (7.8 MW). Similarly, the need overlaps to a degree with the RA AAH, with the time of the needs occurring between HE16 and HE18 in 2023 and HE15 and HE19 in 2024.

CESA understands that there may be two major concerns with our recommendations.

First, CESA understands that the slight overlap of the need for distribution reliability and System RA in the AAH period may be viewed as violating MUA Rule 6: "Priority means that a single energy storage device may not contract for two or more different reliability service obligations such that the performance of one obligation renders the resource from being able from being unable to perform the other obligation." This is especially true since both reliability needs are summer needs, where time-differentiation by month or season cannot be pursued. For energy storage, CESA understands that both services could not be provided since the overlapping needs do not leave sufficient time to allow the storage resource to recharge. Under the MUA Framework, these two reliability services would be overlapping and, by the "letter of the law", would not be allowed. However, given the coincidence of these needs to a degree, CESA recommends that SCE seek to adhere to the "spirit of the law" by developing an innovative contracting and operating approach that allows DERs like energy storage to address both needs. CESA commends SCE for more flexibly applying the MUA rules in the past and requests that SCE seek to do the same in this case.

For example, SCE could seek specific DER resources that are dispatched to address the full HE14 to HE21 needs that cover the distribution need as well as the RA capacity need. As CESA understands it, RA resources must "stay in the market" on a month-by-month basis since LSEs "show" their resources for specific months. Meanwhile, in past DIDF cycles, SCE seems to have procured "replacement RA" on a short-term basis during periods when the contracted DER was needed for distribution services; however, such an approach applied in this case may lead to excessively high replacement costs given the tight System RA market. Instead, CESA wonders whether a resource in this case could "stay in the market" and be picked up to deliver energy over a longer timeframe that not only covers the AAH period to avoid RA Availability Incentive Mechanism (RAAIM) penalties but also to deliver on their distribution service needs. Granted, it may be difficult for a resource to be guaranteed being dispatched in the CAISO energy market unless self-scheduled, which could have impacts on the operations and economics of a project. If energy prices do not reflect the distribution capacity need, there may also be economic factors that make it difficult for the resource to be selected. Alternatively, CESA wishes to explore whether capacity differentiation of DER resources or DER portfolios could be pursued to enable this value stacking. Under this model, SCE may be able to allocate portions of their DER resources or portfolio to the RA market and portions to the distribution service need, which ensure that both services can be delivered. For each of the ideas above, we are open to feedback from SCE and other stakeholders on the feasibility of any of the approaches above.

Second, the "yellow flag" for these two Tier 2 projects was that they require an in-service date of June 1, 2023, which creates some forecast uncertainty by falling into the far end of the five-year planning horizon. CESA understands that there may be some forecast uncertainty as a result, but at the same time, there is greater certainty of a System RA shortfall starting in 2021, where any and all incremental preferred resources would go a long way toward avoiding system reliability issues or regressive environmental outcomes (*e.g.*, extending once-through-cooling facilities or temporarily re-contracting gas generators). As part of a least-regrets procurement strategy, CESA recommends that the 2019 DIDF RFO seek DERs for the Saugus-Elizabeth and Saugus-Colossus projects with a clear preference for those that can offer and provide both the distribution reliability service sought in the RFO as well as the System RA capacity needed. In doing so, SCE will have option value for DERs that are no longer needed or needed to a different degree for the distribution reliability needs as forecasts change, where the DER could still provide value to SCE in providing System RA. In IRP comments, SCE has highlighted how System RA shortfalls could be significantly more (over 5,000 MW) than what the Commission has directed (2,500 MW) as being needed from 2021-2023 due to unplanned gas retirements. As a result, even if SCE addresses their System RA needs pursuant to the IRP Proposed Decision by 2021 or 2022, there is value in having System RA procured and contracted by June 1, 2023 through this RFO to address future needs. In the past, CESA has recommended that SCE not require all DERs solicited in DIDF RFOs be required to submit bids for both RA capacity and distribution services, but our comments were geared toward providing optionality for market participants. In this case, in order to access the RA option value, CESA recommends that the Saugus-Elizabeth and Saugus-Colossus projects be pursued in the 2020 DIDF RFO with the evaluation criteria reflecting a strong preference and additional value for those that can provide RA capacity as well.

Finally, for the other Tier 2 and Tier 3 projects, CESA agrees with SCE's assessment that these projects have too many 'red flags' to justify solicitation for DERs.

3. **What feedback (if any) do you have on SCE's DPAG meeting(s) to date?**

CESA appreciates SCE's detailed explanation of different distribution grid needs and how it assesses and plans investments for these various needs. Particularly, the presentation on voltage needs and the inclusion of reactive power needs is much appreciated and will drive stakeholder interest and ideas on how DERs could address these needs, whether through the DIDF RFO or through alternative sourcing mechanisms (*e.g.*, tariffs).

4. **What additional information do you need (if any) to determine the feasibility of bidding on a project in the 2019 DIDF RFO cycle?**

CESA appreciates the detailed capacity overloads and load profiles on a year-by-year and hour-by-hour basis, which informs how DER operational requirements would be established. Additional information on how each project rated on the specific prioritization metrics would be helpful (*e.g.*, LNBA $/kW-year), similar to what PG&E provided in their DPAG meeting.

5. **What questions or comments do you have for the Independent Professional Engineer regarding his presentation and review of SCE's GNA/DDOR and candidate deferral prioritization process?**

   CESA has no additional questions or comments for the IPE at this time.

6. **Any additional questions or comments for SCE?**

At the September 17, 2019 DPAG meeting, a question was raised about the reason for fewer offers in the 2019 DIDF RFO, even as the products and contract structures were the same from the previous year. SCE suggested that this may have been that the needs were relatively small, which CESA believes may be true for some developers where small project scale does not fit within their preferences. However, CESA believes a bigger reason for the lack of market participation is the insufficient notice and time to respond to the RFO. While locations were shared in advance, the needs were changing and there was significant uncertainty about the approval of the RFO.

Additionally, CESA recommends that the DPAG stakeholders be provided the information to review the two licensing projects: Alberhill Licensing Project and Mira-Loma-Jefferson Line Licensing Project. While the resolution of these projects is appropriately addressed in the CEQA proceeding, this stakeholder group may be able to provide insights into the viability of DER alternatives, which was discussed at the DPAG meeting as being within the scope of the CEQA proceeding.

For future DPAG meetings, though it does not have to be this 2019 DIDF cycle, CESA would like to explore with SCE, IPE, and the Commission on whether resiliency (microgrid) needs are best addressed through the DIDF process. The DIDF only looks at planned capital investments that could be deferred by DERs, but the DIDF may limit the assessment of DERs to the relative economic value of the non-wires alternative relative to capital "wires" investments, such that DERs may not fare as well within this framework. For example, there may be additional benefits of DERs in offsetting onsite diesel consumption that would not be accounted for in the head-to-head comparison. Additionally, if microgrid investments were to be included in the DIDF, CESA seeks to understand whether the utility investment would entail not only distribution capital investments but also generation resources, which may be needed for microgrid configurations. Currently, as explained at the DPAG meeting, SCE indicated that it does not currently assess or plan for investments to provide resiliency. CESA hypothesizes that the lack of microgrid investments may be due the lack of planning standards for "need" of microgrids, such that the DIDF may never really capture opportunities for DERs to provide microgrid (resiliency) services.

<u>San Diego Gas and Electric Company (SDG&E)</u>

SDG&E did not circulate a survey for DPAG participants to provide feedback on their GNA and DDOR filings and there is little to provide feedback on given the lack of candidate projects identified for potential deferral, but we offer our comments here, nonetheless.

First, CESA appreciates SDG&E DPAG meeting presentation, especially in taking a more careful circuit-by-circuit assessment of thermal capacity and back-tie service needs and whether these two services need to be coupled carte blanche. The coupling of these services was a major issue during the 2018 DIDF cycle, so it would be helpful to learn about SDG&E's changing view on this matter from a technical grid perspective.

Second, CESA requests that SDG&E more effectively present their GNA and DDOR information to allow for stakeholder review. In trying to see how the GNA and DDOR filings aligned, CESA identified discrepancies in the information reported for the same facility IDs in each spreadsheet. At the September 18, 2019 DPAG meeting, SDG&E explained that these were due to "modeling errors". For stakeholders who are seeking to understand various grid needs, it is difficult to assess opportunities for deferral by DER alternatives if data in the GNA and DDOR filings are not cleaned up or explained clearly if not matching.

Finally, CESA seeks to understand if the lack of planned investments beyond 2022 is due to SDG&E pursuing just-in-time projects, which was raised in the DPAG meeting. SDG&E explained that the net load impacts from the CEC forecast has resulted in no needs through 2023. Since deferral opportunities only arise when there is a planned investment in the five-year planning horizon, CESA wonders if the lack of projects on the far end of the planning horizon is tied to this type of procurement approach. Furthermore, given that substation and sub-transmission projects seem to require a longer look-ahead based on our experience with SCE's and PG&E's DPAG meetings, CESA wonders whether such longer forecasts are conducted and if so, why they do not show up in SDG&E's GNA and DDOR filings.

Conclusion

CESA appreciates the opportunity to provide these informal comments and hope these responses are helpful. Please do not hesitate to reach out if you have any follow up questions or would like to discuss further.

Sincerely,

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