BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters.	Application 15-07-002 Application 15-07-003 Application 15-07-006
(NOT CONSOLIDATED)	
In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	Application 15-07-005
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COMMENTS OF THE CALIFORNIA ENERGY STORAGE ALLIANCE ON THE ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING COMMENTS ON POSSIBLE IMPROVEMENTS TO THE 2020 DISTRIBUTION INVESTMENT DEFERRAL FRAMEWORK PROCESS

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In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the California Energy Storage Alliance ("CESA") hereby submits these comments on the *Administrative Law Judge's Ruling Requesting Comments on Possible Improvements to the 2020 Distribution Investment Deferral Framework Process* ("Ruling"), issued by Administrative Law Judge ("ALJ") Robert M. Mason III on November 8, 2019.

I. INTRODUCTION.

CESA appreciates the opportunity to provide our comments and recommendations on possible reforms to the Distribution Investment Deferral Framework ("DIDF"), including the Grid Needs Assessment ("GNA") and Distribution Deferral Opportunity Report ("DDOR") filings. To date, CESA has observed incremental improvements and progress made to open DIDF to greater opportunities for distribution deferral for more cost-effective distributed energy resource ("DER") solutions, which deliver savings to ratepayers and support the reliability and resiliency needs of the distribution grid. The investor-owned utilities ("IOUs") have been key partners in making the DIDF work and CESA commends the IOUs for generally supporting enhancements to the DIDF to consider the procurement and deployment challenges and realities of DER solutions.

In support of further enhancements to the DIDF, the Ruling raises a number of important questions and possibilities of how DER solutions can support a broader range of distribution grid needs, including urgent ones such as distribution resiliency, and how the viability and likelihood of success of DER solutions to defer planned investments can be improved. Generally, CESA believes that the Commission is asking the right questions, and as such, we offer our responses to the questions as not only a representative of the energy storage community but also as an invested stakeholder in the Distribution Planning Advisory Group ("DPAG").

II. RESPONSES TO QUESTIONS.

Below, CESA provides our responses to select questions.

Question 1: To what extent did the IOUs have common, comparable datasets for the 2019 GNA/DDOR filings and in what ways could the 2020 filings be improved in this regard?

CESA recommends further standardization of the GNA and DDOR datasets in order to streamline stakeholder review and provide market participants with a common understanding of viable deferral opportunities. We also generally support the recommendations from the independent professional engineer ("IPE") report to keep datasets manageable. In particular, CESA recommends that the candidate deferral opportunities also include additional information on potential charging restrictions on the overloaded circuit(s), if such loading limitations are applicable. Such restrictions have been identified in the request for offers ("RFO") process as a complicating factor, which would benefit from discussion and evaluation in the DPAG process prior to RFO launch. While the DIDF pertains to a broader range of DERs, energy storage resources have played a major role in the DIDF process to date, so a consideration of such restrictions could inform assessments of the viability of deferral and/or consideration of contracting and operational approaches to work around these restrictions.

Question 1a: To what extent did San Diego Gas and Electric, specifically, provide GNA/DDOR data and documentation that was comparable in scope and detail to that provided by SCE and PG&E?

CESA has encountered difficulties in assessing the GNA and DDOR data and documentation submitted by San Diego Gas and Electric Company ("SDG&E") in their GNA and DDOR filings. For example, while certain distribution grid needs were identified in their GNA for specific substations or circuits, those needs were not reflected in the DDOR filing at the same substations or circuits, which the SDG&E team later explained at the DPAG meetings was due to those needs being "eliminated" after accounting for load transfers and "modeling discrepancies". To support transparency and greater accessibility to stakeholders, CESA recommends that SDG&E's filings be presented more consistently with explanations for any differences between the two GNA and DDOR filings at any given location and be made more similar to those provided by SCE. In general, the filings should be reviewable by stakeholders as standalone documents without needing or requesting additional information from SDG&E to explain any differences or discrepancies.

<u>Question 2</u>: **To what extent do the IOUs assert confidentiality over data that do not require confidential treatment or require overly burdensome processes for participant access to confidential materials? Please provide specific examples.**

At the direction of the Commission, CESA believes that the IOUs have moved away from overly broad confidentiality treatment over categories of data in the GNA and DDOR filings. Going forward, CESA generally recommends that the Commission establish a policy that broad categories of data *not* be made confidential unless the IOUs make such requests and demonstrate the need for confidential treatment on case-by-case basis.

<u>Question 3</u>: **Should all planned investments be shown on the IOU's Distribution Resources Plans data portals (online maps). SCE Alberhill Substation was not shown on SCE's portal, for example. In what ways do discrepancies between the online maps the GNA/DDOR filings still exist that should be corrected.**

Yes, as licensing projects such as the Alberhill Substation project are more broadly considered in the DIDF, CESA believes that such projects should be included in the online data portals and maps.

<u>Question 4</u>: **What modifications would increase the likelihood that planned investments that address voltage, reliability, and resiliency needs are prioritized for deferral?**

The key barriers to DER alternatives deferring investments that address voltage, reliability, and resiliency needs are related to the timing requirements for solution deployment/installation. For in-front-of-the-meter ("IFOM") energy storage solutions, the interconnection process under the wholesale distribution access tariff ("WDAT") has been reported to take 1-3 years on average depending on whether the interconnection applicant is seeking deliverability or whether the project qualifies for an independent study process. Meanwhile, for behind-the-meter ("BTM") DER solutions, there are customer acquisition and interconnection timelines that can take 2-3 years to address a deferral need. To address these timing considerations, CESA recommends that the Commission: (1) reconsider the sourcing mechanisms to also include tariff-based mechanisms, which could potentially streamline the procurement and deployment timelines of DER solutions; (2) simplify, clarify, and reform incrementality rules to leverage other sourcing mechanisms for BTM DER solutions that ultimately support more cost-effective and streamlined procurement and deployment of BTM DER solutions; and (3) consider how greater data transparency into load forecasts and load service connection requests can support DER procurement in longer timeframes and with greater modularity and optionality. We address each of these ideas further in subsequent responses to questions.

<u>Question 4a</u>: **Should reliability and resiliency needs be separated in the 2020 GNA and DDOR filings to allow for consideration of resiliency needs, specifically?**

Yes, CESA believes that reliability and resiliency needs should be separated given that the respective needs are unique and subject to different planning standards and/or performance requirements. Similar to how the IOUs have been encouraged to bifurcate and separately define the performance requirements for distribution capacity needs versus distribution reliability needs, resiliency needs should be defined and specified as a separate "product". Understandably, traditional "wires-based" planned investments can address multiple grid needs at once, but bundling the service requirements can make it challenging for stakeholders to differentiate the distribution grid needs (*e.g.*, capacity versus reliability versus resiliency) as well as foreclose on innovative possibilities for portfolios of DER solutions to address specific needs (*e.g.*, whereas some DERs can better address capacity needs, others could be positioned to address resiliency needs). Even if a single DER project or counterparty can address the multiple grid needs, separate definition and specification of the different needs (*e.g.*, reliability versus resiliency) will support the DER provider in developing a creative or innovative solution, such as by leveraging the multiple-use application ("MUA") rules adopted in Decision ("D.") 18-01-003 to differentiate the capacity or time of the energy storage resource to deliver on both needs. However, without this differentiated and need-specific information, DER providers will have more difficulty in most effectively crafting a DER solution to address the multiple grid needs.

While supportive of the consideration of resiliency needs in the DIDF, CESA encourages the Commission and the IOUs to set the foundation and establish a common understanding of the existing or potential planning practices and standards for resiliency projects. From our experience in the DPAG and in reviewing the GNA/DDOR filings to date, the IOUs have yet to propose resiliency-related or microgrid investments. To our knowledge, the Commission has also yet to provide more detailed guidance on resiliency services and investments to inform whether and how the DIDF process could assess resiliency-focused investments, other than to adopt a broad definition of resiliency (microgrid) services as one of the four distribution grid services eligible for the Competitive Solicitation

Framework in Rulemaking ("R.") 14-08-013.[1] By setting the foundation for the IOUs to propose traditional wires-based investments that address resiliency needs, then stakeholders can also be informed in how to assess these planned investments for potential deferral opportunities by DER solutions.

<u>Question 4b</u>: **Should the IOUs each identify a value for lost load and/or resiliency value and apply it to the prioritization metrics? IOUs already identify a cost associated with avoided outage minutes in their General Rate Case (GRC) filings, for example. This could be used in the interim for the 2019 DIDF cycle while resiliency values are, potentially, further defined in other CPUC proceedings.**

Yes, CESA supports the use of a value for lost load in the interim to capture some resiliency value to planned investments, which should be ascribed to DER solutions if they are able to defer the planned investment and deliver equivalent or more resiliency value. However, the use of the value for lost load should only be used in the interim as the Commission potentially considers and adopts a value of resiliency as part of the Microgrids proceeding (R.19-09-009), which CESA believes to be the more appropriate venue to address these matters because it will likely develop a value that could be applicable to the reasonableness assessment of utility investments as well as for the procurement, deployment, and operations of DER solutions via tariffs, programs, or rates.

The broader consideration and applicability of the value of resiliency in R.19-09-009 is more appropriate because CESA has general concerns that the consideration of DER solutions in the DIDF process will limit the resiliency value of DER solutions to an avoided cost perspective, whereby DER solutions will only

[1] See Ordering Paragraph 2 of Decision ("D.") 16-12-036.

be limited by the avoided or deferred value of the planned investment as opposed to an independent resiliency value attributed to the DER solution. Under a DIDF approach, CESA is concerned that DER solutions will only be considered for resiliency needs whether and if the IOU proposes a traditional infrastructure investment and will be limited or bound to the scope of resiliency service provided by the planned investment (*e.g.*, meeting the full microgrid load for 2 consecutive days versus 5 consecutive days). As such, until the value of resiliency and service standards are established in R.19-09-009, CESA believes the use of the value of lost load in the IOUs' General Rate Case ("GRC") proceedings should only be used in the interim for the DIDF process and recommends that this issue be revisited on how the DIDF can incorporate policy decisions from R.19-09-009 in the long term. With the use of the value of lost load in the short term, however, resiliency investments will at least be considered in the interim.

Question 5: **When GNA/DDOR filings identify a planned investment that is a near-term need, i.e., does not meet the timing screen for deferral by an RFO process, do the IOUs ever implement an IOU-owned and operated Distributed Energy Resources (DER) solution as the least cost or preferred solution? If not, each IOU should explain why. For disclosure purposes, should each IOU identify these types of DER solutions in their GNA/DDOR going forward, e.g., in the list of planned investments not prioritized for deferral in the DDOR?**

In the interest of ratepayers, the IOUs should consider all potential investment types, not just traditional infrastructure-based capital investments but also IOU-owned and operated DER solutions, including if the timing screen for deferral is not met. CESA supports the disclosure of such DER solutions in their GNA and DDOR filings going forward, even though they would likely not represent deferrable investments in their DDOR filings.

<u>Question 6</u>: **Should a 10-year planning assumption and forecast apply to the identification of all transmission and subtransmission GNA components to better align the GNA with the 10-year DDOR data as directed by the May 7, 2019 Ruling? Similarly, should a 10-year planning assumption apply to any distribution GNA component that is addressed by a DDOR planned investment to be reviewed pursuant to CPUC General Order (GO) 131-D that has transmission components that are not reported in the GNA/DDOR? See also the Pre-Application Project section below.**

Yes, all transmission and subtransmission GNA components should utilize a 10-year planning assumption and forecast to align with the 10-year DDOR data. As the IPE report highlighted, the IOUs should apply a similar 10-year period for the calculation of Locational Net Benefit Analysis ("LNBA") values in the GNA and the DDOR filings.

<u>Question 7</u>: **Should all reliability needs identified in the GNA/DDOR filings be reliability needs that are earmarked within the planning horizon to require mitigation as defined in adopted reliability planning standard or guide (e.g., load shedding would not be allowable under the associated IOU standard)? Should it be assumed that all reliability needs identified are those that the IOUs believe meet a threshold for cost-effective mitigation; a system can never be completely risk free.**

For the DIDF competitive solicitations, CESA supports the use of adopted reliability planning standards within the planning horizon to identify reliability needs and investments that could be deferred. As the IOUs include more planned investments with back-tie benefits and needs, CESA recommends greater planning standards documentation to support stakeholder review of the reasonableness of the planned investments and the determination of service requirements for DER solutions to address these reliability needs. We also seek to further understand how the GRC process ultimately determines whether the proposed mitigation measures are determined to be cost-effective and necessary. Descriptions of those discussions on how the

IOUs prioritize traditional investments and the Commission's determination on these planned investments would support these efforts.

Question 8: **Should all GNAs include a unique project ID that links to a planned investment in the DDOR and to items included in IOU GRC. Refer to SCE's 2019 GNA/DDOR filing. Should it also be assumed that GRCs will include additional investments that do not have a GNA/DDOR project ID? Projects that involve equipment that cannot be deferred by DERs might include, for example, the addition of SCADA (supervisory control and data acquisition) equipment to add visibility to the operation of existing capacitor banks and regulators.**

Having a unique project ID for all planned investments that are deferrable by DERs supports stakeholder review in assessing the DDOR and GRC filings. As such, CESA supports this recommendation. In particular, following project IDs was a challenge in reviewing the GNA and DDOR filings of SDG&E – a suggested area of improvement to support stakeholder review.

Question 9: **See also Attachments 2 and 3 under this topic area.**

CESA has no further comment at this time.

Question 10: **To what extent did the IOU's 2019 DIDF filings present clear explanations about each factor used to establish the tier levels of prioritization? In what ways could the explanations about each factor be improved?**

CESA believes that Southern California Edison Company ("SCE") best presented clear explanations for their prioritization metrics, though we also credit Pacific Gas and Electric Company ("PG&E") for offering useful explanations.

Question 11: **Should a common prioritization-metrics calculations spreadsheet template be used by all IOUs?**

Unless justified by the IOUs, CESA believes that the prioritization metrics and calculations can be standardized. Prior to the regular DIDF cycle, CESA understands that the Commission allowed for some differentiation of prioritization metrics to test out different criteria, opting to "gain experience with different prioritization approaches before prescribing a given methodology for ongoing use."[2] However, with three cycles of the DIDF process under the belt, CESA believes it is reasonable to standardize the prioritization metrics since there is a common theme of DER viability for deferral based on the unit cost of traditional mitigation, duration of the need, year of need, and likelihood of the forecast based on the "lumpiness" of projected load growth. The means by which some of this information is obtained may be different given the different types of measurement and monitoring tools (*e.g.*, use of SCADA or AMI deployment) and the service requirements may differ based on the architecture of the IOU's respective grid, but the underlying metrics for prioritization appear to be common for assessing DER market potential and viability. By standardizing these metrics, CESA believes that the DIDF process will be further streamlined and encourage greater buy-in from stakeholders.

<u>Question 11a</u>: Should SCE's 2019 Excel prioritization-metrics workbook be used as the starting template?

Yes, CESA supports the use of more quantitative and normalized metrics in SCE's prioritization-metrics workbook as being the best starting template for all IOUs to use, which effectively force-ranks projects and provide the greatest level of transparency and accountability into the prioritization process. While some level of IOU engineering discretion is reasonable, a more quantitative approach reduces (though does not eliminate) subjectivity to the prioritization process, better allows for stakeholder feedback, and supports a greater understanding of relative differences in "tiers" of projects that could advance toward a competitive

[2] See D.16-12-036 at 48.

solicitation. Overall, CESA generally agrees with the prioritization metrics outlined in SCE's workbook, though there could be some continued discussion on the appropriate weighting of the different factors during the DPAG meetings. As discussed later, CESA also believes that value stacking opportunities should be incorporated into the prioritization process if such opportunities exist. Regardless of whether the IOU is seeking to procure for grid service needs beyond those considered in the DIDF, the value stacking opportunities would highlight the potential for cost-effective DERs (*i.e.*, lower cost) to be procured to address the deferral need since the costs for DER investment and deployment would be covered to some degree by other programs or procurement mechanisms.

Question 11b: What improvements could be made to SCE's Excel workbook of prioritization metrics (e.g., include the complete Locational Net Benefit Analysis calculations worksheets set in the same prioritizations workbook and ensure that each column has a descriptive heading that is explained in full in the text of the GNA/DDOR filing)?

For both the GNA and DDOR filings, CESA believes that one major area of improvement for all of the IOUs is to better report on "spot load" forecasts, which can lead to DER deferral opportunities to not be pursued due to forecast uncertainty concerns as well as timing-related screening out of opportunities if such large development-related load additions materialize with lead times that are too short to run an RFO for DER solutions. As CESA understands it, such spot load forecasts are reported to the California Energy Commission ("CEC") with at least three years of line of sight, but our experience in the DIDF and DPAG process has been that the reporting of such forecasts can be inconsistent.

Among the IOUs, CESA believes that SCE has been the most consistent in reporting on spot-load related forecast uncertainties through their "weighted likelihood by asset" prioritization metric in their workbook. In the interest of transparency and consistency, CESA recommends that all IOUs adopt a similar prioritization metric that should also be supplemented by a legend/key and explanations to the determination of these quantitative scores.

Furthermore, despite the uncertainty of such spot-load forecasts, the prioritization process should also consider how DERs can provide greater option value to mitigate planned investments that face large and potentially sudden "swings" in the forecast. This could involve some least-regrets procurement of DERs through a competitive solicitation process to mitigate forecast uncertainty concerns and/or the development of tariff-based options to support streamlined and quicker deployment of DER solutions to address the underlying need. CESA reminds the Commission of the importance of advancing DER tariffs development as part of the DIDF process. Many ideas and proposals were submitted by parties on February 15, 2019 in R.14-10-003 that could potentially be piloted to create additional pathways by which DER solutions could be procured as short lead-time mitigation measures.

<u>Question 12</u>: In what ways could the prioritization metrics be revised to allow for Grid Operator concerns (qualitative assumptions) to be more transparently identified and incorporated such that project's like SCE's Alberhill Substation do not end up ranking high as deferral opportunities (e.g., Tier 1) but with the IOU citing reasons other than the metrics that a planned investment should still be ranked Tier 2, Tier 3, or in a separate Tier 4?

CESA supports the addition of grid operator concerns as part of the qualitative assessment for prioritizing deferrable opportunities. As noted previously, CESA supports quantifiable metrics to the degree possible but also some degree of discretion for the IOUs to make qualitative assessments, such as for grid operator concerns, in prioritizing projects.

Question 13: **For planned investments that have both capacity and reliability needs, should the two needs be presented separately? Or, should they be presented both together and separately for comparison purposes when determining deferral opportunities?**

To the degree that the capacity and reliability needs can be decoupled as two separate services, even if the planned investment(s) addresses both needs, the IOUs should do so in order to help stakeholders understand what is being deferred while also increasing the viability of DER solutions to defer the investment.

Question 14: **Should the need date for the Forecast Certainty metric be replaced by the expected operational date of planned investments in the DDOR (e.g., SCE Alberhill Substation and PG&E Estrella Substation projects)? See also the Pre-Application Project section below.**

CESA believes that both the need date and the expected operational date of the planned investments should be included in the DDOR, though the actual prioritization and final decision process to determine which projects advance toward a competitive solicitation and how mitigation measures are pursued should be based on the expected operational date of the planned investment. As CESA understands it, while the need date indicates when thermal limits or other ratings of equipment are exceeded, the expected operational date of planned investments more closely conveys when mitigation measures are actually needed, considering the planned investments likely incorporate the IOU engineers' best estimate of how and for how long no-cost or operational measures (*e.g.*, load transfers) can mitigate distribution grid needs in the short term. This information would inform the lead time that could be provided to DER deferral solutions for procurement, deployment, and construction. At the same time, CESA sees value in also including the need date for informational purposes to support prioritization considerations since, in the interest of providing additional lead time for DER deferral solutions, it may be reasonable and justified to advance a project to a competitive solicitation if the need arises earlier than the expected operational date of the planned investment.

Question 15: **How can the deferral opportunity prioritizations be modified to include more of the value stack to improve the cost effectiveness of DER procurements?**

The actual value stack quantification will likely be conducted during the competitive bidding process, but qualitative prioritization metrics could be developed around other IOU-specific needs and/or system needs that could highlight how DER solutions could stack value or materialize in the competitive solicitation as a cost-effective mitigation measure. In the 2019 DIDF cycle, for example, in assessing the timing and duration of distribution grid needs, CESA recommended a few additional projects be moved from Tier 2 to Tier 1 due to the value stacking potential for DER solutions to mitigate distribution grid needs while also provide Resource Adequacy ("RA") capacity. The current prioritization process does not consider such opportunities unless raised by stakeholders, so CESA recommends that value stacking opportunities be included as narratives in the DDOR reports. Even if an IOU like PG&E only wishes to procure for distribution grid needs in the DIDF process, there are benefits in incorporating value-stacking opportunities in the DDOR since it may inform the likelihood of lower-cost DERs being deployed to address the distribution-focused need. Considering the IOUs' general awareness of broader grid needs, CESA believes the IOUs are well-positioned to include such qualitative assessments, at minimum, as part of the prioritization process.

<u>Question 16</u>: See also Attachment 2, Independent Professional Engineer Recommendations, under this topic area.

CESA has no further comment at this time.

<u>Question 17</u>: Should the existing DIDF approach be applied to Pre-Application Projects to determine if the project or components of the project can be addressed by DERs prior the IOU filing a formal project application with the CPUC?

In our view, the existing DIDF approach would be a good fit for identifying DER alternative portfolios to pre-application projects since the DPAG involves actual DER providers that can provide insights into assessing the viability of project deferral. CESA believes that such industry insight and expertise may be missing in the application process for these licensing projects because of the resource intensity of participating in these individual proceedings. The DIDF/DPAG represents an efficient venue to assess DER alternative portfolios to pre-application projects.

<u>Question 18</u>: Assuming Pre-Application Projects continue to be included in the GNA/DDOR filings, are additional DIDF guidelines and other reforms needed?

CESA believes that it is important that pre-application projects be considered under several different configurations. The Alberhill and Estrella projects, for example, are large projects meeting a number of different needs that together justify the utility expenditure. In whole, the project may not be deferrable by DER solutions. However, should projects be configured to reflect the underlying components of the larger project, projects may be deferred in part or in whole through DER solutions. Identifying discrete pieces of the larger proposed project in addition to the needs that those pieces would resolve early in the project proposal process could greatly facilitate their consideration for deferral in the DIDF process. The IPE, in his recommendation on process improvements, noted there should be "consideration of planned investments with a combination of needs (e.g., capacity, reliability, and/or resiliency) should include an evaluation of how the needs ***could be segregated*** in some cases" [emphasis added]. This is particularly important for these large projects subject to GO-131-D review

<u>Question 18a</u>: Should the projects be identified in the GNA/DDOR filing but not prioritized into Tiers 1 to 3?

CESA supports the inclusion of pre-application projects in the GNA/DDOR filings as well as their prioritization into the tier structure, at the very least for informational purposes.

<u>Question 18b</u>: Should the projects be identified in the GNA/DDOR filing and be prioritized into Tiers 1 to 3, but be exempt from the DIDF RFO process?

Unless additional DIDF guidelines are developed or broader reforms to the application approval process for licensing projects is considered, it may be premature to include pre-application projects in the DIDF RFO process. CESA believes it may be worthwhile to include deeper discussions on whether and how pre-application projects could be considered in the DIDF process. Considering the high dollar value and long lead time of these licensing projects, CESA believes that there is tremendous opportunity for DERs to serve as a cost-effective alternative.

<u>Question 18c</u>: Should the Tier 4 option be eliminated or further defined for the GNA/DDOR filings?

CESA does not see a need for a Tier 4 option. It should be sufficient to rank pre-application process in the normal three-tier structure and consider whether these projects, such as for the Estrella project, could be broken into smaller, deferrable projects.

<u>Question 18d</u>: Should it be further clarified that these projects will continue to be treated like any other GNA/DDOR planned investment in the annual DIDF cycles?

At least for information purposes, these projects should be treated and assessed like any other planned investment in the DIDF process. To the degree that specific needs can be segregated, CESA believes that such components of projects could be deferred and avoid the need for GO-131-D/CEQA review. In the Estrella project, for example, CESA observed that only the reliable need was not deferrable, but if the other needs could be addressed through DER solutions, such projects could reasonably be considered for an RFO as part of the DIDF process.

<u>Question 19</u>: Should regulatory and permitting costs be included in the cost of planned investments identified in the GNA/DDOR filings? Should they also be itemized separately to allow for comparison to the cost of a DER deferral opportunity that may not require extensive permitting and environmental review?

Yes, regulatory and permitting costs should be included in the planned investment costs in order to better support cost-effectiveness comparison with DER solutions, which may be exempt from California Environmental Quality Act ("CEQA") review. Additionally, for other DER solutions, CEQA related costs may not be applicable. As such, there could be advantages to DER solutions in obviating the need to incur such regulatory and permitting costs.

<u>Question 20</u>: When a planned investment is expected to undergo review pursuant to GO 131-D, should project cost and the Cost Effectiveness metric be based on the filing information for the GO 131-D proceeding or the latest GRC information (e.g., SCE

Alberhill Substation cost is about $200 million per the GRC or about $500 million per SCE's GO 131-D filing details)?

Yes, this seems reasonable, though it makes most sense for there to be an explanation of why there is a discrepancy between these two values and, if one is more accurate at the time of the DIDF filing, that number should be used.

Question 21: **What modifications to the IPE review process could improve DIDF outcomes?**

CESA has no recommended modifications at this time and supports the IPE's review process to date and their recommendations, as attached in the Ruling, to streamline their review process. Overall, the IPE's observations and analysis have been helpful and insightful.

Question 22: **See also Attachment 2, Independent Professional Engineer Recommendations, under this topic area.**

CESA agrees with several recommendations made by the IPE. As noted earlier, we agree that projects should have their constituent needs – *e.g.*, reliability, capacity, resiliency – broken out into discrete projects. We also agree with the IPE's call for greater transparency, in particular "key assumptions such as discount rate, revenue requirement multiplier, inflation assumptions, O&M factor, and book life are important for calculating LNBA values." One qualification on this recommendation would be that data be treated as confidential only where clearly applicable under current Commission rules or where the Commission has made on a categorical or case-by-case basis that the data is confidential. The utilities should not be unilaterally making determinations that data is confidential particularly as this proceeding has had numerous instances where the utilities have claimed that expansive amounts of data is confidential due to it being "commercially sensitive" or of "security concern", only to be rebuffed by the Commission.

<u>Question 23</u>: What modifications to the DIDF Advice Letter filing and RFO launch/review process could improve DIDF outcomes?

In general, CESA has found the modifications adopted by the Commission for the 2019 DIDF cycle (*e.g.*, consolidating GNA/DDOR filings, streamlining DPAG meetings) and improvements made to the filings by PG&E and SCE to be very helpful. Since timing is important to a competitive solicitation, the Commission should consider processes by which the DPAG stakeholders could potentially arrive at and present consensus recommendations, if such consensus can be reached prior to the Advice Letter filing, in order to minimize the odds of Protests to the Advice Letter(s), which could delay the timely launch of the IOU's respective annual DIDF RFO. Indeed, the Commission has done much to accelerate the annual DIDF cycle and was timely and efficient in its review of PG&E's recently filed contracts. However, the utility contracting process could be streamlined. PG&E, for example, took approximately six months from shortlisting projects to executing contracts; this timeline could be shortened dramatically.

<u>Question 23a</u>: Should a no-regrets concept for excess capacity procurements be considered to more fairly assess the Cost Effectiveness and Market Effectiveness of DERs in comparison to traditional, wired solutions and DERs?

1) ***The pro-forma contract should be revised to allow for excess capacity or options for additional capacity.***

Yes, CESA supports the incorporation of a no-regrets concept for excess DER capacity procurements. We have observed that this concept is already being pursued in practice as contracts are negotiated and the IOUs are made aware of new information (*e.g.*, updated forecasts), whereby contracts are executed for capacity with an excess margin to account for forecast uncertainty or as a contingency measure for deployment-related failures or shortfalls. However, instead of addressing changes in load forecasts by modifying and putting projects back out to bid, these forecast uncertainty issues can be more efficiently addressed by incorporating optionality within contracts that allow them to adapt to growing needs. Such risk mitigation practices are reasonable and should be reflected in the DIDF process when assessing and prioritizing projects. Specifically, the standard *pro forma* contracts should allow the IOU to procure more capacity as needed if still cost-effective. These capacity add-on options would be approved as part of the contract approval process for the DIDF RFO, even as the IOUs are procuring against the original need. Managing this risk in contracts as opposed to the procurement cycle is more efficient.

2) The solicitation process should include contract terms reflective of the projected needs.

Contract terms for DIDF projects are sometimes shorter than the projected need. Should the underlying load growth driving a projected need continue beyond the standard term of the contract, the contract term should be extended to be commensurate with the term of the need. For example, if peak load growth driving a distribution need is projected to continue for the full ten years of the forecast, the contract term should be for the full ten years as well.

<u>Question 23b</u>: What Competitive Solicitation Framework reforms are needed to improve DIDF outcomes?

As discussed later, CESA recommends reforms to the incrementality framework adopted in D.16-12-036 to the Competitive Solicitation Framework. Otherwise, CESA believes that the Competitive Solicitation Framework has worked well in terms of the planning/RFO process.

Question 23c: Should IOU ownership of DERs be allowed in DIDF RFO procurement?

CESA supports allowing IOU-owned DER projects to be considered as part of the DIDF process, with the appropriate controls in place. If DER solutions are the most cost-effective solution to address a distribution grid need, CESA sees no reason to preclude projects based on ownership model. However, to ensure a level playing field with third-party-owned DER solutions, CESA believes the appropriate controls need to be put in place. The Commission has already laid out a potential starting point for such a framework for third-party-owned and IOU-owned projects to compete in the same solicitation, as outlined in Appendix A of D.19-06-032. Before allowing for IOU-owned DER solutions in the DIDF RFO procurement process, CESA recommends stakeholder review and comment on the framework to ensure the appropriate controls are in place.

In particular, CESA sees advantages in allowing for IOU-owned projects for planned investments with less than three years lead time, especially if projects can take advantage of IOU-owned land and expedite interconnection processes. However, to ensure a level playing field, information on forecasts and planned investments must be made equally available to third parties and the evaluation criteria must be thoroughly assessed and vetted to ensure that projects are evaluated fairly without bias toward ownership model. If such information is not made equally available to third parties as part of the planning process, CESA is concerned that IOU-owned projects would have an unfair advantage in these competitive solicitations.

The utilities should also ensure that imperfections in the load forecasting are not resulting in needs being identified with too short a lead time to allow for a solicitation. For example, SDG&E identified no deferrable project because all projects failed the timing screen: the need was too near term to be put out for bid. The "spot loads" that were driving projects may or may not be something that can be forecast farther out but this should be scrutinized. Large housing developments, for example, will file regulatory documents three years in advance of construction suggesting that some spot loads may be far more forecastable.

Question 23d: Should IOU customer programs, e.g., energy efficiency, augment or provide back up for competitive RFO-based procurements to help ensure DER deployment instead of traditional, wired solutions?

Ideally, programs should be accurately accounted for in the load forecasts that underly IOUs' distribution plans and therefore avoid projects indirectly. This is an area of ongoing refinement in R.14-08-013. Above and beyond the value of the resources as captured in the forecasts, customer programs should absolutely be considered as a sourcing mechanism to augment RFO-based sourcing mechanisms. In particular, CESA sees merit in layering "adders" to existing programs to support and target deployments to the areas of need and to shape their operations as needed. CESA believes that these ideas were considered in various DER tariff proposals, including one submitted by SCE regarding their proposed rider tariff.[3] Again, CESA encourages the Commission to revive discussion on DER tariffs

[3] See *Response of Southern California Edison Company (U 338-E) to administrative Law Judge's Ruling Directing Proposals for Distributed Energy Resources Tariffs* filed in R.14-10-003 on February 15, 2019 at 9-12.

Question 24: **How might the IOUs coordinate DIDF RFO solicitations and procurements with other DER procurements related to other CPUC proceedings, e.g., resource adequacy, energy efficiency, demand response, microgrids, etc.?**

As noted in our response to the value-stacking question, CESA believes that the IOUs are well-positioned to provide narrative descriptions of additional solicitations and procurement opportunities in other proceedings. From our understanding, the IOU procurement teams conduct RFOs for multiple different programs and needs. Since there appears to be some overlap of personnel for all IOU procurement efforts, CESA believes they are well-positioned to report on these value-stacking and coordination opportunities. Granted, there may be other areas of opportunity that the IOUs miss or have no view into, considering the growing number of load-serving entities ("LSEs") in California, but that might be an area where DPAG stakeholders can provide additional insights. In the DPAG meetings, for example, CESA has seen little community choice aggregator ("CCA") representation and participation. To encourage efficient and potential joint procurement opportunities to realize value stacking benefits, CCAs should be encouraged to participate in these planning and procurement efforts.

Question 25: **In what ways could Net Energy Metering and Self-Generation Incentive Program resources participate in the DIDF RFOs while meeting incrementality requirements?**

CESA believes that reforms to the incrementality rules are long overdue. The current incrementality framework has led to the less-than-robust participation and competitiveness of BTM DER resources in recent DIDF RFOs. CESA thus urges the Commission to consider the incrementality proposal prepared and submitted by CESA and Stem in the Multiple-Use

Applications ("MUA") Final Report in R.15-03-011, where we laid out more refined definitions and frameworks that more accurately reflect the incrementality of BTM energy storage resources.[4]

Specifically, CESA believes that refinements are needed to how incrementality is assessed relative to the planning assumptions that are generated by the CEC and disaggregated down to specific circuits and feeders by the IOUs. Importantly, CESA notes that the CEC's Demand Analysis Working Group ("DAWG") meetings on November 21, 2019 and Integrated Energy Policy Report ("IEPR") workshop on December 2, 2019, which has highlighted several limitations to forecasting approaches today on BTM energy storage resources. For BTM storage, the CEC detailed how it used the SGIP Weekly Statewide Report to determine the installed capacity to date and how it applied different methodologies for forecasting storage adoption for the residential sector (where almost all systems are paired with PV) and for the non-residential sector (where most systems are standalone).[5]

As noted in the MUA Final Report, there are varying levels of uncertainty or inaccuracies related to the location, growth trajectory, and operational profile of DERs that go into these planning assumptions. When procured, BTM DERs may deviate to varying degrees from these assumptions, even as CESA has observed incremental improvements to the CEC's forecasting

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[4] See Appendix A of *Compliance Report of Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39 E) and San Diego Gas & Electric Company (U 902-E) on Behalf of the Multiple-Use Application Working Group* filed in R.15-03-011 on August 9, 2018 at 60-78.

[5] For non-residential storage forecasts, the CEC proposed a methodology to take the average of 2018 capacity, 2019 capacity, and the SGIP program queue (multiplied by some factor conveying "likelihood of installation"). In CESA's view, there are some concerns with this approach since the forecast is limited by the SGIP application queue, not taking into account changes in incentive rates, capital costs, or rate schedules, and appears to constant linear growth based on these anchor historical data points (*i.e.*, trend analysis). For residential storage forecasts, the CEC proposed a high and low adoption methodology, with the former linking adoption to PV adoption (by calculating a "storage adoption rate" based on storage capacity added in 2018 as a ratio of total installed PV capacity, which is then multiplied against the PV forecast) and the latter using historical trends, similar to what is being used for non-residential storage forecasts. The mid case would use the average of the high and low scenarios.

approach. For example, for non-residential standalone storage systems, it is very difficult to predict or forecast charge and discharge behavior due to fluctuations in customer load and the need to mitigate non-coincident demand charges. Instead, the incrementality framework should be refined to add greater transparency into these planning assumptions to support the development of meaningful and fair bids, and/or to establish a new clearer process by which BTM DERs could be removed from the forecast to provide clearer incrementality determinations (*i.e.*, thereby removing uncertainty to the incrementality of BTM DERs and by establishing with greater certainty through contracts the location, deployment levels, and operational profile of BTM DERs). Further details on CESA's views and recommendations on incrementality framework refinements are included in the MUA Final Report, including examples involving Net Energy Metering ("NEM") and Self-Generation Incentive Program ("SGIP") resources.[6]

Additionally, CESA adds that the Commission recently provided an important clarification around SGIP-funded energy storage projects that should inform the incrementality discussions and decisions for the DIDF RFOs. Specifically, in D.19-08-001, the Commission clarified that "customer payment or reduced rates received for enrollment in an economic [demand response] program integrated into the [California Independent System Operator] or the [Demand Response Auction Mechanism] is considered payment for services, not an incentive."[7] Furthermore, D.19-08-001 differentiated SGIP as an incentive program for installed storage systems that meet upfront eligibility requirements in contrast to a payment for grid services such as for energy storage systems that participate in demand response ("DR") programs or procurement mechanisms.[8] Considering these affirmations made by the Commission, CESA believes that there is

[6] *Ibid* at 68-73

[7] D.19-08-001 at 66 and Conclusion of Law 40.

[8] D.19-08-001 Finding of Fact 65.

compensation-based incrementality of these resources in delivering the energy needed to address distribution grid needs.

<u>Question 26</u>: **Should a formal review and adoption of IOU reliability standards for the subtransmission and distribution systems occur (i.e., all grid components not subject to the NERC, WECC, and/or CAISO planning standards)? As a starting point, for example, refer to PG&E's Guide for Planning Area Distribution Facilities. It identifies distribution planning guidelines and criteria, forecasting processes including those for DERs, and includes a section on GNA/DDOR requirements. Compare the PG&E GNA/DDOR internal plans to Attachment A to the CPUC May 7, 2019 Ruling that outlines GNA/DDOR requirements.**

CESA supports a formal review of reliability standards.

<u>Question 27</u>: **IPE verification that reliability needs identified in the GNA/DDOR filings for distribution and subtransmission components (i.e., non-CAISO jurisdictional) are reflective of an adopted standard and request a copy of the standard. Similarly, IPE verification that reliability needs related to the transmission system, if any, (i.e., CAISO jurisdictional) are reflective of an appropriate, adopted NERC, WECC, and/or CAISO transmission planning standard (e.g., Estrella Substation Project and the associated Cholame Substation and 70-kV N-1 reliability needs identified by PG&E).**

CESA has no comment at this time.

<u>Question 28</u>: **Identify a select group of planned investments (case studies) from the GNA/DDOR filings for the IPE to investigate in greater detail.**

CESA has no comment at this time.

<u>Question 29</u>: **In what ways would additional coordination with other CPUC proceedings improve DIDF outcomes (e.g., R.14-10-003 for Integrated Distributed Energy Resources, R.14-07-002 for Net Energy Metering, R.19-09-009 for Microgrids, R.17-07-007 for Rule 21 reform, R.12-11-005 for Self-Generation Incentive Program, R.13-09-011 for Demand Response, R.13-11-005 for Energy Efficiency portfolios, R.18-04-019 for Climate Adaptation, R.18-10-007 for Wildfire Mitigation Plans, or others).**

There are many areas of potential coordination with other proceedings (as briefly discussed below). The Commission may wish to revive the DER Action Plan as the central document to ensure that the DIDF is coordinated with each of these other proceedings:

- **R.19-09-009, R.18-10-007:** Incorporation of adopted policies, practices, and definitions (*e.g.*, for resiliency) would inform resiliency-related investments.
- **R.12-11-005, R.14-07-002:** Expectations for performance/operations and the significance of the payments or incentives would inform incrementality interpretations in the DIDF RFOs.
- **R.13-09-011, A.17-01-012, *et al*:** Performance evaluation methodologies could inform how demand response resources in the DIDF RFOs should also be assessed.
- **R.17-07-007:** Various interconnection processes and policies will play an important role in ensuring DER solutions are deployed in a timely and safe manner.

Question 30: **Comment on the potential value of similarly scoped study (i.e., case study) or larger-scale study of this kind to help improve future DIDF outcomes. With respect to the incrementality discussions in this proceeding, note that BTM potential for adoption studies can be designed to assume that SGIP and NEM do not apply.**

CESA does not find a BTM potential adoption study to be useful to the refinement of the incrementality framework. While a market potential study would be helpful in establishing a roadmap for DERs, such a study would be rife with uncertainty and inaccuracies that could just serve to further complicate the incrementality framework. Instead, CESA refers the Commission to our response to Question 25 as a better pathway for addressing incrementality.

Question 31: **To what extent are the GNA/DDOR filings reflective of the Grid Modernization Plans filed by the IOUs in their respective GRCs, especially with respect to enabling the procurement and interconnection of cost-effective DERs empowered to provide a stack of benefits including, among other services, the deferral of traditional grid investments and mitigation of power shutoff risks related to heightened fire danger?**

CESA cannot comment on the extent of alignment; however, we encourage the IOUs to seek alignment and pursue value stacking opportunities for distribution reliability and resiliency, where possible.

<u>Question 32</u>: **Should the GNA/DDOR filings identify all instances where: a. A GO 131-D Advice Letter process is expected to be required instead of a formal application filing for transmission or substation projects (i.e., a Notice of Construction or NOC filed with the CPUC); or b. The IOU anticipates that a public agency other than the CPUC will conduct the CEQA analysis for a DDOR planned investment to be filed with the CPUC pursuant to GO 131-D?**

CESA has no comment at this time.

III. <u>CONCLUSION</u>.

CESA appreciates the opportunity to submit these comments to the Ruling. We look forward to working with the Commission and stakeholders in this proceeding.

Respectfully submitted,

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CALIFORNIA ENERGY STORAGE ALLIANCE

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