

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking Regarding Policies, Procedures, and Rules for Development of Distributed 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 (Filed July 1, 2015)
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**COMMENTS OF THE CALIFORNIA ENERGY STORAGE ALLIANCE
ON ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING ANSWERS TO
STAKEHOLDER QUESTIONS SET FORTH IN THE ENERGY DIVISION STAFF
PROPOSAL ON A DISTRIBUTION INVESTMENT DEFERRAL FRAMEWORK**

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August 7, 2017

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In accordance with Rules of Practice and Procedure of the California Public Utilities Commission (“Commission”), the California Energy Storage Alliance (“CESA”)¹ hereby submits these comments on *Administrative Law Judge’s Ruling Requesting Answers to Stakeholder Questions Set Forth in the Energy Division Staff Proposal on a Distribution Investment Deferral Framework*, issued on June 30, 2017 (“Ruling”).

I. INTRODUCTION.

CESA supports the Commission’s efforts to create a framework that establishes greater transparency into the distribution grid planning process and that identifies opportunities for cost-effective distributed energy resources (“DERs”) to meet identified grid needs through deferral or avoidance of traditional capital investments. The distribution deferral pilots proposed in the Integrated Distributed Energy Resources (“IDER”) proceeding (R.14-10-003) represent an initial testing of the Distribution Investment Deferral Framework (“Framework”) as they solicit cost-effective DERs to defer capital investments needed to increase distribution capacity. CESA commends the investor owned utilities (“IOUs”) and the Commission for kickstarting this

¹ 8minutenergy Renewables, Adara Power, Advanced Microgrid Solutions, AES Energy Storage, AltaGas Services, Amber Kinetics, American Honda Motor Company, Inc., Bright Energy Storage Technologies, BrightSource Energy, Brookfield, Consolidated Edison Development, Inc., Customized Energy Solutions, Demand Energy, Doosan GridTech, Eagle Crest Energy Company, East Penn Manufacturing Company, Ecoult, EDF Renewable Energy, ElectriQ Power, eMotorWerks, Inc., Energport, Energy Storage Systems Inc., GAF, Geli, Green Charge Networks, Greensmith Energy, Gridscape Solutions, Gridtential Energy, Inc., Hitachi Chemical Co., IE Softworks, Innovation Core SEI, Inc. (A Sumitomo Electric Company), Johnson Controls, LG Chem Power, Inc., Lockheed Martin Advanced Energy Storage LLC, LS Power Development, LLC, Magnum CAES, Mercedes-Benz Energy, National Grid, NEC Energy Solutions, Inc., NextEra Energy Resources, NEXTracker, NGK Insulators, Ltd., NICE America Research, NRG Energy, Inc., Ormat Technologies, OutBack Power Technologies, Parker Hannifin Corporation, Qnovo, Recurrent Energy, RES Americas Inc., Sharp Electronics Corporation, SolarCity, Southwest Generation, Sovereign Energy, Stem, STOREME, Inc., Sunrun, Swell Energy, UniEnergy Technologies, Viridity Energy, Wellhead Electric, and Younicos. The views expressed in these Comments are those of CESA, and do not necessarily reflect the views of all of the individual CESA member companies. (<http://storagealliance.org>).

process that will drive significant learnings on how to structure a sustainable Framework going forward.

Overall, the Distribution Investment Deferral Framework Staff Proposal (“Staff Proposal”) lays out a well-structured and clear process by which the IOUs will conduct annual Grid Needs Assessments (“GNAs”) and how they will feed into the Framework. As the Framework becomes a regular mechanism by which to identify deferral opportunities, CESA recommends that the Framework ensure transparency and consistency in the GNA and screening process. CESA also recommends that the Framework not artificially limit DER opportunities to provide deferral services with strict timing screens or by failing to adequately consider use of existing DER projects in the planning and solicitation process. Greater opportunities for DERs to succeed in providing deferral services should be provided by: (a) clearly defining grid needs, standardizing grid products, (b) carefully applying screens as appropriate for the grid need, market potential, and solicitation mechanism, and (c) ensuring the Framework is workable for sourcing mechanisms other than competitive solicitations.

In these comments, CESA answers certain of the questions posed in the Staff Proposal. CESA generally supports the Distribution Planning Advisory Group (“DPAG”) and the solicitation process as outlined in the Staff Proposal, and thus does not provide answers to questions related to those topics at this time, although CESA may respond to other parties’ comments. CESA also does not provide any comment at this time on questions relating cost recovery.

II. GRID NEEDS ASSESSMENT.

Question 1: What procedural vehicle (e.g., Application, Motion, Advice Letter, Compliance Report) is best suited for the IOUs’ GNA submissions? Does the GNA need to be entered into the record in order to be referenced in the selection of distribution deferral opportunities?

Similarly, does the Commission need to acknowledge, approve, modify, or otherwise dispose of the GNA? If so, by which vehicle should this occur?

CESA recommends that the Commission adopt an advice letter process for the IOUs' GNA submissions since these are intended to be annual planning processes and require timely turnarounds to initiate the solicitation and deployment processes. Regulatory approval processes are lengthy for Applications, which in CESA's view, are not necessary for the GNAs since these are planning documents - not requests for approval of specified and quantified investments.

Furthermore, as discussed in the Staff Proposal and in these comments, the timing screen limits the number of deferrable projects – *i.e.*, short-lead-time needs are deemed to be not cost effective for DER alternatives and long-lead-time needs are subject to greater forecast uncertainty and thus prone to instances where the grid need does not materialize. As a result, there is a small subset of deferrable projects within the three- to five-year lead-time range in which DER alternatives would be viable. A process consisting of unduly extensive regulatory approval processes may create lost opportunities for DER alternatives as the identified grid needs no longer have the appropriate lead time for DER alternatives by the time that the GNA is approved.

At the same time, the advice letter process allows stakeholders to vet the load and DER growth forecasts in addition to how these forecasts are disaggregated downstream to more distributed parts of the grid. Some time will be needed to understand how the IOUs set assumptions for flexible resources such as demand response and energy storage. These assumptions are critical to identification of grid needs and certainly require stakeholder vetting. CESA notes that one of the purposes of this proceeding is to more transparently involve stakeholders in the distribution grid planning process.

The advice letter process for the GNA would allow stakeholders to provide input into the short-listing process as well, rather than just involving them in the process after the deferrable projects have been shortlisted through the DPAG. The lead-time assumptions for various DERs may need to be vetted in the GNA to the extent that it identifies a short-list of deferrable opportunities by applying the timing screens as proposed in the Staff Proposal. For example, throughout the Staff Proposal and IDER pilot process, CESA believes that the perception that new and existing DERs cannot be deployed for a deferral service under three years to be unreasonable and not reflective of other past solicitations (*e.g.*, Aliso Canyon emergency energy storage procurement). Stakeholders should be given an opportunity to understand how the IOUs applied various assumptions and screens to arrive at the GNA and the resulting shortlist of deferrable projects.

Question 2: Referencing Figure 1, by which date should the GNA be submitted, such that the IOUs have sufficient time to complete the annual planning process, compile the relevant data, and allow for sufficient DPAG review? By which dates should other steps in the DRP process occur? (This topic is addressed further in Section 2.4.4)

CESA does not have ‘hard’ recommendations on the timeline for the annual planning process and DPAG review. CESA only notes that sufficient time for IOU annual planning, stakeholder review of the GNA, advice letter approval of the GNA, and DPAG review of the shortlisted deferrable projects be given. The timeline in Figure 1 appears to present such a reasonable timeline.

Question 3: How should the Commission set thresholds for the type and magnitude of grid needs and planned projects that are reported in the GNA? Should grid needs and planned projects only be reported for the four distribution services identified in the IDER Competitive Solicitation Framework, and over a given magnitude?

The Commission should identify grid needs using the screens outlined in the Staff Proposal. CESA understands that there may be complexities that the IOUs must consider, and thus some flexibility should be granted, but for the purposes of creating a more streamlined and actionable distribution planning process annually, it may be reasonable to set some technical, timing, or financial thresholds for identifying planned projects in the GNA that are medium-term candidates (3-5 years) for a competitive solicitation for DER alternatives.

At the same time, while thresholds may be prudent to apply for *planned projects*, it may be beneficial to apply lower or no thresholds for reporting on distribution *grid needs at large*. CESA highlights the distinction between grid needs and planned projects. Planned projects are specific deferrable opportunities that meet specific thresholds or criteria for a potential competitive solicitation, while grid needs provide IOUs, planners, and developers with foresight into grid needs in the future, even as they are not guaranteed to materialize into a planned project or competitive solicitation in the near future. Transparently providing grid needs data in the GNA may inform the Commission and developers of *potential*, albeit not guaranteed, longer-term deferral opportunities. CESA recognizes that forecast uncertainty related to DER growth and load shapes increase with longer outlooks. Despite the uncertainty, identification of overall grid needs will help guide third-party developers who may begin to deploy DERs at some of these potentially deferrable locations, thus positioning these DER assets to have ‘steel in the ground’ that can be more readily re-purposed to provide multiple applications, including distribution deferral in the long-term. In doing so, the IOUs can avoid the ‘deployment challenge’ regarding the lead time of DERs, which open up new distribution deferral opportunities that can be provided cost-effectively by DERs, such as voltage support – a

distribution service that was characterized by the IOUs and the Staff Proposal as being provided by short-lead-time, relatively cheap, traditional capital resources.

CESA acknowledges that deployment of DERs for such a long-term *potential* deferral purpose raises the question about incrementality, and whether at that point in the future, the DER will eventually be incorporated in the load forecast and therefore avoid the deferral opportunity altogether. This question is valid and unresolved, and should be addressed in this proceeding. In the meantime, CESA believes there are significant benefits to all parties in providing this grid needs information in the GNA without filters or criteria (or with low-threshold filters if the reported GNA becomes too unwieldy, data-intensive, and uninformative with a loose definition of ‘grid need’). Meanwhile, questions about incrementality and compensation can be addressed in the course of the proceeding.

At this time, the four distribution services identified in the IDER Competitive Solicitation Framework (“CSF”) are sufficient for the GNA, but there may be other types of distribution services that could be provided by DERs in the future. The Framework should not preclude other types of distribution services to be added as an eligible service in the future.

Question 4: How should grid needs and planned projects be characterized in the GNA? How is such information presented in the GRC, and how can that inform its presentation in the GNA? What information do the IOUs need to provide in order to articulate the distribution upgrades that could be technically deferred by DERs? How should data be formatted and presented in both downloadable datasets and online maps?

To the degree possible, the IOUs should clearly define the grid needs and planned projects. In particular, CESA points to the IDER pilot proposed by Pacific Gas and Electric Company (“PG&E”) as a good example in which the distribution capacity sought to defer a traditional infrastructure project from 2020-2024 is well-defined and ‘productized’. The deferral

‘product’ clearly points out that PG&E is seeking dispatchable resources that may be called on a day-ahead basis for up to six times a month but not more than three consecutive days and for not more than 12 days total during the summer (June to October) from 3-9pm. The information is presented in a way that defines a clear need and provides greater certainty to the DER community seeking to provide DER alternatives to defer the traditional infrastructure project. The standardized product or contract approach also reduces the solicitation timeline that creates greater opportunity for DERs to be procured to meet the deferral need. At the GNA stage, it may not be necessary to specify a deferral product to this degree, but the IOUs should provide specific information on the magnitude, duration, and features (*e.g.*, dispatchability, response time) for the identified distribution grid need.

Moreover, the GNA should also include information on how the various screens were applied to identify which projects should be considered for the solicitation-based approach. Transparency in this regard will ensure that screens are not inappropriately applied. How the timing screen, for example, characterizes the lead time for DER alternatives may not be accurate and would benefit from stakeholder input. This information would also enhance the DPAG’s efforts in reviewing the GNA and to finalize a list of deferrable projects from the shortlist. This information should also be provided as part of the report appended to the advice letter filings of the utilities through which they request authorization to move forward with solicitations.

Question 5: Are there any confidentiality or market sensitivity issues surrounding certain attributes of grid needs and/or planned projects? How can access to such types of data best be handled?

CESA has no comment at this time.

Question 6: How can the Commission verify that all grid needs and planned projects over the established thresholds are included in the GNA?

CESA has no comment at this time.

III. DEFERRAL SCREENING.

Question 7: Should the screens in Table 1 be used for the initial deferral screening process, or should certain screens be added or removed?

CESA supports the use of the four screening criteria: technical, timing, financial, and forecast certainty. These four screens should be used to identify deferrable criteria, but CESA has some concerns about how the timing and financial screens are applied, which are discussed further in our response to Question 8 below.

Question 8: Do you agree with the IOUs' further characterization of the technical and timing screens presented in Tables 2, 3, and 4? What can be added or modified? How can the aspects of the Deferral Framework or DER sourcing mechanisms under development in IDER be honed to address the illustrative timing constraints described in Table 4?

CESA disagrees with the IOUs' characterization of the timing and financial screen in Table 4. First, the Staff Proposal characterizes the 'sweet spot' for deferral opportunities for DERs to be in the "intermediate term" timeframe (3-5 years) that consists of a reasonable balance between sufficient lead time for DER sourcing, reasonable forecast certainty, and sufficiently high cost of traditional infrastructure investments for intermediate-term grid needs. CESA agrees with this assessment for intermediate-term timeframes. Due to forecast uncertainty, CESA agrees that there may be limited deferral opportunities for DERs in the 'long term' timeframe (6-10 years) as needs change or never materialize, even though it may still be helpful to report this information in the GNA as discussed in CESA's response to Question 3 above.

However, the Staff Proposal may be ignoring an important deferral opportunity for DERs with 'very short term' and 'near term' timeframes (noted in the Staff proposal as having a 0-1.5 years and 1.5-3 years timeframes, respectively). The explanation in Table 4 is that near-term deferral opportunities requires expedited solicitation and regulatory approval processes and that

DER solutions may not be cost-effective given the smaller size and lower risk of conventional projects for grid needs (*e.g.*, small thermal capacity needs, voltage support) that fall within these timeframes. In the IDER pilots, it was revealed that this timing screen eliminated all voltage support projects from consideration due to the 0-2 year lead-time for such grid needs.² When considering the utilization of existing DER resources to meet certain deferral needs, the timing screen may be relaxed for these deferral opportunities. In this Framework, it is important to consider how existing DERs with either spare capacity or the ability to create spare capacity through repurposing to provide distribution deferral services while adhering to contractual obligations. The greater consideration of existing projects will overcome lead-time and cost concerns (from the financial screen), increasing the number of deferrable projects to those that can provide voltage support and reliability back-tie services.

For very short term and near-term timeframes, it may be feasible to procure existing DER resources to address certain grid needs prior to the next peak season once *pro forma* contracts and services/products are standardized to reduce the time required to source, contract, and approve contracts. If *pro forma* contracts are developed and clearly define the attributes sought (*e.g.*, response time, dispatchability, timing of need), DERs may be procured within a 1-2 year timeframe.

In addition, as noted above, existing projects or short-lead-time projects can serve as a backstop and provide contingency planning if the initial winning DER project fails to be deployed or perform according to expectations. Ultimately, the consideration of existing DERs will entail a policy discuss around double counting and compensation, which will affect whether and at what cost existing DERs can be procured to meet any identified grid need.

² Staff Proposal, p. 9.

The Staff Proposal importantly notes the need to develop streamlined non-RFO sourcing mechanisms that allow for short-lead-time grid needs to be met by DER solutions.³ From a competitive solicitation perspective, the timing screen may be appropriately focused on intermediate term timeframes (3-5 years). However, the use of tariffs, reverse auctions, and/or pre-approval processes may be mechanisms by which short-lead-time needs such as voltage support can be provided at least cost without an extensive solicitation process, which avoid the lengthy process and resources needed to conduct an RFO.

Question 9: Do you believe a maximum customer penetration threshold criterion, such as that employed by PG&E in the IDER Incentives Pilot, is reasonable for use in the ongoing Deferral Framework? Explain.

PG&E screened out a potential reliability (back-tie) deferral project because it applied a ‘maximum customer penetration threshold criterion’ in its IDER pilot. Specifically, because the potential deferral project served a very large number of customers to pilot a non-wires alternative, PG&E opted against including this in its IDER pilot solicitation.⁴ If this question is asking whether the high number of customers at the location of the deferral opportunity should eliminate the deferral opportunity, CESA disagrees. Use of a maximum customer screen presumes that non-wires alternatives are not sufficiently reliable to provide deferral services for a point on the grid serving a large number of customers as compared to wires solutions. In the subsequent section, the Staff Proposal discussed PG&E’s metrics to prioritize the candidate projects, which placed higher relative priority for deferral projects serving a larger number of customers. Given this, PG&E’s maximum customer screen in the IDER pilot may be due to the fact that non-wires alternatives have not been widely tested, and for the purposes of the pilot and

³ Staff Proposal, p. 30.

⁴ Staff Proposal, p. 19.

learning exercise, it is reasonable to limit the scale of the project and any corresponding potential impacts. However, once proven, the Commission should seek to scale the Framework without the use of a maximum customer penetration threshold. With the right contracts and performance incentives, DERs should be able to reliably provide deferral services to any number of downstream customers. Additionally, from a cost-effectiveness perspective, it would be preferable to procure DER alternatives that produce cost savings for a broader base of customers.

IV. **PRIORITIZATION METRICS.**

Question 10: Is SCE’s prioritization methodology from the IDER pilot adequate for use by the DPAG in the ongoing Deferral Framework? What metrics, if any, should be added, removed, or modified?

CESA believes that the Commission should adopt only the project timing certainty, financial assessment, and distribution topology prioritization metrics at this time. In effect, this would be utilizing the timing and financial screens for the deferral opportunity identification process as a prioritization metric, as well as prioritizing projects that serve a larger customer base, thereby providing greater benefit across a larger customer base for DER providers to target. Use of these prioritization metrics will identify the highest potential and cost-effective deferral opportunities with greater certainty suited for a competitive solicitation.

However, CESA recommends that the DER attributes and market assessment metrics be removed. First, it is unclear to CESA what the purpose of the DER attributes metric is. CESA assumes that the intent of seeking fewer DER services in the deferral opportunity is to reduce complexity in the bid evaluation process and create greater assurances of delivery of the deferral service. CESA seeks clarification on this metric, but believes that it should be removed and/or does not deserve weight equal to the other prioritization metrics.

Second, the market assessment prioritization metric, as Southern California Edison (“SCE”) defines it, will likely not yield a competitive solicitation because DER providers would be bidding to secure the few large customers in the area to provide the deferral service. With such a small base of customers, the solicitation for the deferral service will likely involve a very small number of bidders that do not yield least-cost outcomes. Furthermore, the application of this metric also limits the opportunities for the use of DERs in contingency planning as there is a smaller base of customers with DERs on which to fall back on. Finally, the risk of failure to deliver the deferral service may be reduced with a portfolio of DERs through geographical and customer profile diversity.

Question 11: Provide comments or recommendations on the need for further prioritization after the initial deferral screening process. How can the overall screening process, from initial deferral screening criteria through to prioritization, be modified and/or improved?

CESA does not have comments on any additions or modifications to the initial screening criteria or prioritization metrics. However, CESA recommends that the screening criteria and prioritization metrics be consistent across the three IOUs to provide clarity, certainty, and long-term visibility to market participants. The Staff Proposal’s adoption of SCE’s prioritization metrics as applicable for other IOUs presumably is intended to achieve this.

CESA points to the useful comparative example of the joint New York utilities in filing a similar Distributed System Implementation Plan (“DSIP”) in setting consistent planning assumptions and processes, grid/market operations, and data collection/access.⁵ The New York utilities are in the process of developing non-wires alternative (“NWA”) suitability criteria

⁵ *Joint Utilities Supplemental Distributed System Implementation Plan*, Case 16-M-0411, November 1, 2016.

matrices and datasets in NWA solicitations that are standardized across the utilities.⁶ In their Supplemental DSIP filed on November 30, 2016, the joint New York utilities developed similar NWA suitability criteria based on project type, timeline, and cost, which led them to conclude that distribution capacity (or load relief) and some types of reliability projects are the best NWA candidates in the near term.⁷ A similar consistent Framework should apply to California's IOUs. Likewise, CESA recommends that the Commission use lessons learned from the New York distributed planning process in developing California's Framework. To the credit of the Commission and the California IOUs, CESA commends the Framework for its greater detail and specificity in how to identify deferral opportunities.

V. **CONTINGENCY PLANNING.**

Question 17: To what degree should the Commission prescribe the types of potential mitigations for contingencies at various stages of DER project development? Or, should such mitigations be determined by the DPAG on a case-by-case basis, depending on the specific types and magnitudes of grid needs that are being deferred?

The Commission should not prescribe specific types of potential mitigations for contingencies but should have an overarching requirement for DER-based potential mitigations at the construction and operation stage of the deferral process. Any specific contingency plans may need to be determined on a case-by-case basis by the IOUs in consultation with the DPAG. CESA thus agrees with what is generally proposed in Table 9 to the degree that DERs should be included as part of contingency planning ahead of traditional capital projects. To ensure that DERs are included in contingency planning, it is therefore critical that the identified grid need serve a large base of customers, as noted in our response to Question 10 above.

⁶ *Ibid*, pp. 5, 10.

⁷ *Ibid*, pp. 43-47.

CESA, however, recommends a few modifications to the contingency planning process. At the solicitation stage, while it is understandable that there is no means by which DERs can be incorporated in contingency planning, CESA recommends that the Framework include a feedback loop to understand the reason why DERs were not able to be procured for the deferral opportunity – *e.g.*, whether there was something that affected the bidding process. These feedback loops will improve the solicitation process going forward. At the construction stage, CESA recommends that there should be a clear notification process to procure runner-up DER alternatives to ensure that these DER solution providers are reasonably able to provide the deferral service in a cost-effective and timely manner. Finally, at the operation stage, CESA recommends the removal of turnkey DER deployment, since it raises concerns about the IOUs taking over the contracted DER to optimize for grid services instead of customer services. Instead, CESA recommends that contingency planning involving DERs should leverage and procure existing DER deployments, perhaps among the bidders involved in the solicitation, with shorter lead times to meet the deferral needs.

Question 18: To what level of detail should the IOUs scope out contingency plans for specific distribution deferral projects in requesting Commission approval of selected deferral projects?

Contingency planning should be made explicit and clear to provide more certainty to DER providers and to ensure that there is a defined process at which point the IOUs will begin considering DER alternatives. The specifics should be outlined in the DER contract with milestones that mark when the deployment or operations of the DER solution is not meeting the deferral need, at which point the IOU must prepare for DER-based contingencies. The milestone approach is needed to ensure timely implementation of DER-based back-up solutions.

VI. CONCLUSION.

CESA appreciates the opportunity to submit these comments on the Ruling and looks forward to working with the Commission and parties going forward in this proceeding.

Respectfully submitted,



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Date: August 7, 2017