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 (Filed July 1, 2015)
And Related Matters.	Application 15-07-007 Application 15-07-008

CLEAN COALITION COMMENTS

on **STAKEHOLDER QUESTIONS SET FORTH IN THE ENERGY DIVISION STAFF PROPOSAL ON A DISTRIBUTION INVESTMENT DEFERRAL FRAMEWORK**

Doug Karpa, J.D., Ph.D.
Policy Director

Clean Coalition

16 Palm Ct.

Menlo Park, CA 94025

415.860.6681

Doug@clean-coalition.org

August 7, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

I. The Distribution Investment Deferral Framework must facilitate the prompt deployment of Distributed Resources on a technology neutral and cost-effective basis.

The Clean Coalition submits these comments in response to the ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING ANSWERS TO STAKEHOLDER QUESTIONS SET FORTH IN THE ENERGY DIVISION STAFF PROPOSAL ON A DISTRIBUTION INVESTMENT DEFERRAL FRAMEWORK, dated June 30, 2017

The Distribution Investment Deferral Framework (DIDF) must be designed to maximize ratepayer value and the social benefits of distributed energy resources (DER) by creating a framework that is responsive to distribution needs in a technology neutral way. The Staff Proposal provides a useful framework, although the approach could be improved by:

1. Developing a new prioritization metric that expressly prioritizes grid needs according to their importance for the grid, the urgency of the needs, and the cost-effectiveness of the proposed project.
2. The timeline of the process should incorporate a notice of potential needs to enable DER developers to start the initial work of developing solutions well before any Request for Offer (RFO) is launched
3. The project evaluation process must use all available data to ensure an accurate assessment of all proposed projects. Limitations from confidentiality concerns must be substantially limited to ensure the public benefits from decision-making based on the best information available.
4. The Distribution Planning Advisory Group (DPAG) must include DER market participants from various segments of the industry. On-the-ground experience developing resources cannot be substituted and cannot be effectively provided by any other segment of stakeholders.

We strongly support Staff's focus on developing a process that provides flexibility and shortens the timeline from need identification to full deployment of a solution.

II. Description of the Party

The Clean Coalition is a nonprofit organization whose mission is to accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise. The Clean Coalition drives policy innovation to remove barriers to procurement and interconnection of DER—such as local renewables, advanced inverters, demand response, and energy storage—and we establish market mechanisms that realize the full potential of integrating these solutions. The Clean Coalition also collaborates with load serving entities, DER developers, and municipalities to create near-term deployment opportunities that prove the technical and financial viability of local renewables and other DER.

III. Clean Coalition Comments in Response to the Stakeholder Questions

1. What procedural vehicle (e.g., Application, Motion, Advice Letter, Compliance Report) is best suited for the IOUs' GNA submissions?

The key consideration is that the procedural vehicle include sufficient detail and allow sufficient time to be thoroughly vetted by stakeholders. The grid needs assessment (GNA) process should allow for stakeholders to address any deficiencies in the GNA and to ensure that the assessment does not neglect key analyses. While an informal review process may be adequate, a mechanism should ensure that the GNA will reflect consideration of stakeholder input in advance of use in GMPs and their review. Where stakeholders believe the GNA is still deficient, this may be addressed in formal review of the GMP.

Furthermore, the GNA should be entered into the record to allow consideration and reference in any Commission decisions that draw upon its information.

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?

The GNA needs to be incorporated into the distribution planning process. However, Figure 1 appears to suggest that the GNA would be developed in parallel to the distribution planning process, which would be inappropriate. Given the 7 month time frame allowed, we would recommend that the GNA be available in the November to December timeframe to allow comment and finalization for late December through January. As noted in response to Q1, the schedule should allow for stakeholder/DPAG feedback regarding the GNA, while respecting the time sensitive nature of use of the GNA under ever changing circumstances. To the extent that the GNA can reflect the application of a needs assessment criteria formula, the primary focus should be on refinement on these criteria, with subsequent review limited only to whether the formula properly applied these criteria.

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 DIDF should not be restricted to larger projects, although only larger projects should be subject to individual competitive solicitations to address each identified grid need. Competitive solicitation is an inherently burdensome process that imposes substantial participation costs on both utilities and bidders. Thus, competitive solicitation should be used only when the process will generate significantly lower total ratepayer costs than alternative, less burdensome procurement methods. For practical purposes, competitive solicitation should not be used where the ratepayer cost of performing a solicitation is greater than the estimated savings from the process. Consequently, a minimum magnitude threshold is appropriate for using competitive solicitations.

Smaller projects should still be included within the GNA, but under a streamlined, alternative selection process. For example, grid needs may be addressed through bundled project procurement, targeted programmatic incentives, or standard offers that do not require or are inappropriate for competitive solicitation. By using a hybrid approach, the DIDF should be able to maximize shareholder value even for smaller grid needs.

While the four distribution services identified as subject to DER deferral may reflect existing application of DER functions, additional services are reasonably anticipated to be available in the relatively near future. For example, updates in inverter standards will significantly impact their functionality, including both proposed changes in Phase I between real and reactive power prioritization in operation, and the adoption of Phase II & III communication and functionality standardards. In addition, the ability of a distribution system operator to signal, dispatch, and monitor both DER responses and more granular grid operations will be itself greatly influenced by grid modernization implementation, including DER management systems. The ability to predict, control, and change how DER respond in each location, and their ability to autonomously provide extremely rapid and coordinated response, will certainly open up additional applications. As such, this proceeding should anticipate that additional services will become available and allow for their incorporation as this occurs. DPAG and stakeholders will be able to review new candidate services and applications in the regular GNA and grid modernization processes.

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?

The characterization of needs and presentation of data should be specific to the purpose for which it is being used--whether planning, solicitation, or budgeting authorization.

For solicitation purposes, the needs must be clearly defined in technology-agnostic terms of the electrical performance and services required for each location, including the timeframe in which the need must first be addressed and the progression of the need over time. These questions have been largely addressed by the DPAG in the Integrated Distributed Energy Resources (IDER) DER Incentive Pilot, and in the Locational Net Benefits Assessment (LNBA) tool and map layers. Furthermore, the Commission should consider presenting data as early in the process as is practical in advance of any solicitation or final approval to allow a maximum lead time for the development of proposals. Such an approach would allow for faster solicitations and higher quality bids.

For planning and budgeting purposes, it may be more appropriate to categorize the types of need and present information reflecting the locational distribution and scale of needs, aggregated totals by time period (e.g., hour, season, year). This information will be of substantial value in the Integrated Resources Plan (IRP) as the Commission and stakeholders consider the impact of alternative resource portfolios. It will also be valuable in the IDER and other proceedings where targeted procurement and the development of compensatory rates and tariffs are scoped.

In addition to defining the distribution upgrades that might be deferred by DER, it will be important to clearly describe the current limitations preventing DER from contributing to any classes or categories of grid needs for which it is deemed inapplicable. This will greatly assist stakeholders to define and evaluate where to devote attention to expanding DER services, including the type and value of grid modernization investment associated with enabling such services.

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?

Confidentiality of grid needs or planned projects creates a barrier for third parties to develop efforts to meet grid needs. When confidentiality concerns prevent a robust response by DER providers to meet the GNA needs, then the the DIDF will fail to identify or implement potentially cost-effective DER solutions and will result in fewer bids.

Fundamentally, needs cannot be addressed or prioritized if necessary information about the need is not available. DPAG and LNBA have substantially addressed this issue by defining the degree of granularity required to define the needs, and balancing the necessity of providing market indicative value without undercutting competitive dynamics. Standard compensation offers can be developed based on fully confidential information if needed, requiring only release of information defining the locations where compensation will be offered and the remaining level of compensation available at that location corresponding to the date of service.

Confidentiality factors regarding disclosure of individual customer information are addressed in other proceedings and should be informed by any *new* needs and opportunities identified here, but need not otherwise be revisited.

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

First, primary focus of the DIDF process should be on refinement on the needs assessment criteria, with any subsequent review of GNA limited to whether the formula properly applied these criteria. This review of each GNA should be performed by the assigned Independent Professional Engineer (IPE), including random sampling of grid sections and reported needs assessment against independent analysis of these samples.

Second, the Commission should consider requiring annual reporting of all upgrades meeting GNA inclusion criteria that were neither included in the GNA nor the result of emergency conditions. In the event of significant failure to appropriately include projects in the GNA, the Commission may consider financial penalties, including discounting any rate-based reimbursement for such projects. Ultimately, the Commission should adopt policies and practices that align the interests of regulated monopolies with the interests of ratepayers to promote utility performance.

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

The initial screens constitute a reasonable set of categories for project review, although the specific criteria and weighted valuation of each category clearly requires further development, including review by the DPAG and IPE. For example, rather than a blanket prioritization of long-term over short-term deferrals, the analysis should weigh the value of deferrals for the timeframe over which a deferral is made. It is entirely possible that a large value, short-term deferral has a greater value than a longer term deferral of a smaller investment.

One of the key issues is who will be determining whether projects meet the screens, and how this will be done. Clearly, the treatment of DER in Tables 2,3, and 4 suggests that projects might "fail" screens based on ungrounded pessimism rather than a serious look at the abilities of DER to meet technical needs. As discussed in the response to the following question, Tables 2 and 3 do not represent a consensus conclusion of members of the LNBA Working Group or DPAG regarding the ability of DER to address system constraints and associated grid needs related to some reliability, resiliency, equipment operations & maintenance, or emergency preparation and response.

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?

No. Tables 2, 3, and 4 comprehensively ignore various services that DER can and do provide. The screens in tables 2, 3 and 4 would represent an unwarranted bias against the use of DER and have little justification based on real world experience or engineering considerations. Thus, the screens in these tables must be comprehensively reassessed and developed with a solid evidentiary basis. In addition, any such screens must be periodically reexamined and revised as DER capacities expand to allow for additional grid services.

These screens contain unrealistic limitations on the use of DER to meet grid needs. For example, Table 2 appears to suggest that microgrids cannot provide resiliency services. In fact, DER are already providing resiliency services in a number of applications through inverter ride-through settings and within microgrid deployments. Solar and storage (PVS) projects around the country are already providing resiliency back up services to the grid. For example, a recent 28 MW_{AC} PV plus 20 MW_{AC} x 5-hour duration (100 MWh) PVS system is under construction in Kaua'i to provide resiliency services and to displace diesel generation.

Similarly, Table 3 suggests that DER cannot provide non-capacity reliability, but this ignores a suite of advanced planning tools and capabilities that can allow distributed networks of DER to provide these services. Distributed advanced inverters, advanced distribution management services, and advanced modeling can provide better fault detection and sectionalization services in conjunction with DER deployment to provide these ancillary services and to maintain current for fault detection on particular grid segments. In the event of a transmission outage, for example, DER can provide capacity and also support fault detection through a combination of contingency and restoration planning tools to design the locations and settings of protective devices and a network of advanced inverters to provide real time information to optimize the function and location of protective devices. These elements can combine to provide interruption services under some new approaches to fault detection at lower voltages. In addition, repair and replacement needs can potentially be avoided if the functions of the deteriorated infrastructure is met through DER deployments much as upgrades can be avoided. Table 3 also asserts that DER cannot reduce outage duration, even though DER such as storage can in fact reduce outage duration through black start, reconnection, ramping and resiliency services. Finally, to the extent that distribution upgrades are needed to meet minimum infrastructure to serve customers, some of these upgrades may be avoidable through the use of DER at some locations. Table 4 also suggests constraints on the timing of DER services that are belied by real world deployments. One of the major advantages of many DER (particularly modular solar or storage facilities) is the ability to deploy the infrastructure rapidly. The primary impediment to using DER laid out in Table 4 is not anything inherent in DER, but rather results from a slow and cumbersome RFO process. The issue with meeting distribution grid needs is not that DER fails to meet those needs, but rather that the procurement and regulatory process is not capable of meeting distribution needs. Indeed, Staff recognizes elsewhere that the timing barriers are procedural, not technological. As Staff argues on page 30 of the proposal, there needs to be a non-RFO sourcing mechanism to place non-wires alternatives on an equal footing with distribution upgrades. Given that IDER aims to develop the competitive solicitation framework (CSF) as well as rates and tariffs are scoped for development, there is no rationale for DRP to ignore that work and establish rules or approaches that disadvantage DER. Rather, the IDER proceeding aims to resolve the issues with the RFO process.

Furthermore, there appears to be no evidence to support that DER would not be cost effective at smaller sizes or that DER equipment is more risky than conventional projects. Where externally sourced DER solutions are constrained by procurement timeframes or risk, a utility may install its own DER as a more cost effective alternative to a conventional wires solution. Utility ownership or application of DER should not be ruled out, only subject to appropriate regulatory oversight to avoid anti-competitive market impacts.

For all parties: How can 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?

The planning context requires some kind of pre-approval process to place DER and wire solutions on equal footing for comparison and rapid deployment. It appears that the DIDF envisions a modeling process to assess grid needs, followed by a development of an RFO, followed by a bidding and construction process. For needs that can be determined well ahead of time, such a process might work. However, for shorter term, using pre-approved DER contractors and price constraints would allow utilities to deploy DER far more rapidly and to meet distribution grid needs within shorter time frames.

Additionally, partially meeting an identified need can extend the timeframe for fully meeting the defined need, thereby extending the opportunities to address the need most cost effectively. For example, if annual forecast load growth of 1 MW per year will result in a capacity constraint in three years (2020), then procurement with commencement of delivery of only 1 MW by 2020 will mean that the constraint will not occur until 2021, allowing additional time for preferred solutions. A project that is considered not reliably fully deferrable within the defined timeframe may in fact be partially deferrable with rapid deployment of DER. In these cases, full mitigation can reliably occur with the new timeframe, increasing the number of projects subject to DER mitigation.

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.

No, absent an engineering constraint that would prevent DER from being deployed, there is no need for a maximum customer penetration threshold criterion. DER must be fully considered as a non-wires solution in all cases, unless there is a technical constraint that would prohibit DER. Such engineering constraints would provide the menu of workable solutions more efficiently than any arbitrary threshold that may or may not reflect actual constraints in the configuration of the grid.

Customer penetration projections are only a useful consideration for customer-sited DER, which is a subset of DER deployment potential. Penetration within both the behind-the-meter (BTM or retail) and in-front-of-the-meter (IFOM or wholesale) categories is influenced by value associated with both the utility deferral compensation and other value streams available to the DER owners and operators. As such, "maximum customer penetration" assumptions should be considered one factor, but it is a factor which will vary dramatically under different scenarios.

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?

A consolidated methodology should be developed that incorporate elements from all three metrics to best capture the importance, urgency and cost-effectiveness of upgrades. Since the SCE methodology does not adequately evaluate these critical criteria, it should not be adopted.

Since the purpose of a prioritization methodology is to identify the most important and urgent projects and resolve them to deliver ratepayer value, any methodology should be evaluated against these criteria. Importance should be judged in terms of the number of customers affected and the scale of the project relative to the distribution grid ara. The urgency of these needs should be a function of how soon the distribution project will be needed in light of existing capacity, load growth and customer needs. FInally, delivering ratepayer benefit requires that projects be evaluated based on their ability to resolve significant needs for relatively lower costs. Cost-effectiveness of meeting those needs in turn reflects the value ratio of the benefits of the project to its costs in a technology-neutral manner. Currently, none of the methodologies capture these three dimensions adequately.

The SCE methodology does a poor job of meeting these criteria. First, SCE's methodology expressly elevates the priorities of large industrial users over residential users, even if residential users are numerous. Not only does this implicate serious equity concerns, but the justification for such a prioritization is more grounded in utility convenience than ratepayer value. (*I.e.*, based on the number of customers the utility or an aggregator would need to engage for the project). While this may have been a reasonable metric of project viability for this initial IDER pilot due to uncertainty and lack of experience or supplier maturity in this new market, experience shows that large numbers of small participants can be easily engaged, reliably responsive, and offer access to greater untapped capacity. For example, PG&E's residential AC demand response program and SMUD's residential critical peak pricing large scale pilot among others have demonstrated this potential. The market is new, so the assumptions regarding future performance embodied in the SCE methodology are premature. Furthermore, this metric runs oddly counter to the rationale for relying distribution topology, which seeks to prioritize a greater number of customers again out of ease for the utility in seeking out customers to enroll in DER programs. In fact, both the PG&E and SDG&E more directly reflect the number of customers served by an upgrade, which is a more direct reflection of importance. The PG&E metric in particular uses a simple number of customers and projected size of need to evaluate the importance of the upgrade.

Second, the SCE (and PG&E) methodology employs a rather cryptic "project timing certainty" metric which has an unclear relationship to how soon a project would be needed. This urgency metric of the SCE methodology is less sophisticated than the SDG&E metric of the urgency, which incorporates load growth, weather factors and development in assessing the trajectory of when an upgrade would be needed. This express breakdown of the drivers of urgent needs would provide decisionmakers with greater clarity regarding this component of the methodology

Finally, the SCE methodology does not evaluate cost effectiveness in a technology neutral way. The SCE methodology expressly prioritizes projects that involve less DER, which has no justification in this context. If DER can meet the need, DER developers should be allowed to do so without having the opportunities they can meet downgraded. Such an approach is not technology neutral and will fail to maximize ratepayer benefits by specifically deprioritizing particular projects based solely on what technologies could be deployed to meet these needs. In addition, SCE's methodology prioritizes projects with high capital costs rather than based on ratepayer value. This suggests that SCE's methodology would put expensive projects at the front of the queue precisely because they're expensive rather than based on ratepayer value or cost effectiveness. This may have been appropriate for the pilot in which no more than four projects were allowed, but in an unlimited environment scale is only a factor in assessing the benefit to cost ratio; a larger project with lower B/C ratio should not be prioritized, especially if both can be pursued. Instead, projects should be evaluated based on how much ratepayer value is delivered for the cost of the project. In this regard, SDG&E's evaluation of cost per MW is superior.

Overall, staff should take elements from all three methodologies or employ new metrics to develop a single methodology that accurately captures importance, urgency and cost-effectiveness within the scope of the methodology.

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?

As discussed above, the prioritization methodology should be improved to incorporate importance, urgency and cost-effectiveness in a technology neutral way. The four axis initial screen seems reasonable, although it each of the considerations represent a spectrum, so that it may be worthwhile to evaluate the initial screen as a cumulative score rather than yes/no responses. In particular, without the input of DER developers some of the screens will be difficult to assess (*e.g.*, timing and feasibility).

12.Do you agree with Staff's proposal for the DPAG to consist of IOUs, Commission technical staff, advocates, DER market participants, and an IPE technical consultant? If not, what types of stakeholders should be included or excluded?

The DPAG should include DER market participants with experience developing projects to provide the critical perspective on the realism of the estimates in the prioritization analysis. This expertise cannot be replicated by any other group of stakeholders. In addition, policy advocates who will represent the public interests in renewable deployment should also be represented to bring a policy perspective to the deliberations of the DPAG.

13.D.16-12-036 determined that the actual costs of conventional distribution projects
should be treated as confidential information for the purposes of the IDER Incentives Pilot. Should the Commission apply this same determination to the ongoing Deferral Framework? Are there additional considerations or new information relevant to making this determination?

The practical value of disclosing actual value for ratepayers and market pricing should be determined by trialing both approaches (disclosure of actual value or holding such data confidential, and the results compared. Certainly, withholding this data from market participants in the pilot was appropriate due to the potential risk of bidders clustering near the value. However, the lack of information regarding value can also discourage market participation and competition.

The DIDF should learn some of the lessons of the experience in the pilot. DPAG's non-market participants can accurately assess the cost effectiveness of different options under confidentiality and non-disclosure agreements. However the pilot demonstrated problems with this approach, including inconsistent and unpredictable IOU determination of eligibility. As staff and DER market providers have pointed out, cost disclosure is important in assisting DER providers with screening out economically uncompetitive projects. Ratepayers benefit when DER providers are able to deliver bids under the cost of the traditional projects. Should a substantial number of projects be submitted, the competition among providers who have a realistic possibility of winning contracts should drive costs down further. Ultimately, having a large number of projects proposed for less than the cost of a traditional project can only inure to the benefit of ratepayers.

Finally, standard offers, adjusted as needed to elicit the appropriate level of market response, greatly reduces the cost and related barriers to supplier participation and is likely to result in lower cost procurement, and shorter procurement timeframes.

14.More broadly, which other types of information presented by the IOUs at the Deferral
Framework workshop (reproduced above) can be reasonably construed as market sensitive and/or confidential? Please provide adequate justification and cite all relevant statutory language and/or Commission decisions.

As stated above, limitations on data availability should be kept to a minimum, since the distribution investment deferral analysis will be more accurate and have better public legitimacy if the data used to derive investment decisions for which ratepayers are ultimately responsible are as transparent as possible.

15.Which of the two options detailed above enables the DPAG to most effectively carry out its charge of recommending successful distribution deferral projects for solicitation? Are modifications needed to certain elements of these options, or is there a preferred option that is not mentioned here? Do you foresee any issues related to establishing the DPAG as an "Entity or program established by the Commission by decision" (per P.U. Code §910.4)?

A staff-led process is more likely to be successful and also helps relieve the IPE of responsibilities for process management on top of the presentation of technical expertise. Consensus building and facilitation should be conducted by those with experience in guiding such processes. Consensus building tends to take skill and expertise, so that the leaders of the process should be those best situated to deliver such consensus. Therefore, a staff-led process is preferable to one in which the IPE is having to both offer technical advice as a participant and manage the overall consensus building process.

The Tier 3 process is certainly the best vehicle for delivery of DPAG recommendations, at least for the initial phases. It may be that the Commission deems that a Tier 2 letter may eventually suffice.

As currently formulated, a critical weakness in the DPAG process is that the response by IOUs to DPAF recommendations was not well documented or easily trackable. Itemized responses to each recommendation are necessary for effective review by both DPAG participants, Commission staff, the IPE, and any other stakeholders in the final approval process.

16.Between the adopted vehicle for proposing DPAG Recommended Projects and the IPE's DPAG Report, how can candidate deferral projects that do not achieve consensus be best documented for Commission review and disposition?

Projects could be presented in tiers organized by the degree of support, with both arguments for and against by respective representative parties appended to such projects. We reiterate however that DPAG may not have the practical capacity to review large numbers projects, and efforts should be focused on establishing review criteria and affirming their application rather than on DPAG review of each individual project. To the extent that the GNA can reflect the application of a needs assessment criteria formula, the primary focus should be on refinement on these criteria, with subsequent review limited only to whether the formula properly applied these criteria.

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?

Generally, the DIDF needs a streamlined process for deploying alternative projects should a selected DER project fail to perform. Such a streamlined process should shorten deployment times and reduce risks associated with failure of projects for whatever reason. Developing a roster of alternative and turnkey DER deployments is a solid approach, and, as with the GNA and initial project selection process, a standardized approach or formula for project failure scenario default response is an efficient foundation. It would be inappropriate for wires solutions to be the preferred alternative when DER providers can meet needs more efficiently. However, one would point out that a failure of DER to perform when dispatched is a matter no different than any other resource failure to dispatch or equipment failure and should be handled comparably.

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?

Alternative or runner up projects need not be scoped to the same degree as a selected project unless they are needed, but certainly the initial screen would be reasonable to undertake. The level of detail is likely to be variable depending on the capacity and certainty of the selected project. This level of detail should likely be established by the DPAG during the review process. At minimum, likely alternative projects should be identified from the initial list of bids in order to facilitate rapid deployment of a back up option, and a standardized approach or formula for project failure scenario default response is an efficient foundation.

20.Is Staff's proposal to launch the CSF RFO two months after Commission disposition of DPAG Recommended Projects adequate?

Staff's position that the process needs all possible efficiencies is well taken. Allowing project specific input well in advance of a formal RFO would facilitate both the quality of the DPAG process and the ability of DER market participants to meet distribution needs.

DER market participation will benefit from early identification of need and value in association with the LNBA maps and tools currently under development. This will support supplier preparation in response to specific project identification. Staff's point that efficiencies in DPAG process and the prioritization methodologies depend very much on the ability of DER to meet needs in many instances. Some form of preliminary proposals for various potential distribution will be needed in advance of the DPAG process. Without input from DER market participants, DPAG will mostly be guessing what is realistic and which feasible DER options are available.

A more useful schedule should involve a notice of potential project needs for the list of preliminarily identified needs that will feed into the LNBA and DPAG process. Such a preliminary list approach will allow better communication and synchronization between the Commission process and the development of DER projects by DER market participants. Even if the notice of potential projects includes a general potential need, the location of the need, and perhaps a preliminary prioritization score, DER market participants will be vastly better positioned to develop non-wires alternatives and reduce necessary lead times considerably. This would also function to develop a preliminary list of vendors for the Commission to vet prior to a formal RFO. Once the DPAG Recommended Projects list is released (along with discussion of non-consensus projects), DER market participants who have worked on meeting potential needs would be in a position to provide the Commission with additional information to inform their final decisions. When the RFO is finalized as

quickly as is practicable, DER market participants will also be much better positioned to respond quickly and with better developed proposals.
We also note again that the use of standard offers, adjusted as needed to elicit the appropriate level of market response, greatly reduces the cost and related barriers to supplier participation relative to an RFO bidding process, and is likely to result in lower cost procurement, and shorter procurement timeframes.

22.Do you agree with Staff's proposed Tier 2 advice letter process for minor changes to elements of the ongoing Deferral Framework? How could this proposal be modified or clarified?

Material changes to program parameters that can shape the market and the ability of DER to meet grid needs would likely merit consideration by the Commission, so a Tier 2 letter would be appropriate. For example, changes to prioritization metrics or screening criteria could drive a material shift in the selection of projects and the relative ability of DER to be brought to meet distribution grid needs. Tier 2 letters would be appropriate for some changes that would improve efficiency of the selection process without a material impact on the project selection or the ability of DER to meet distribution grid needs.

Staff should clarify that the Commission would approve changes that could have a material impact on the ability of DER to meet distribution needs through a Tier 3 letter, while other changes would be appropriate for Staff approval. While the workshop process is valuable for achieving consensus, the prospect of significant changes to the prioritization and screening process would introduce unwelcome uncertainty into the process for developers who already face substantial uncertainty in bringing projects forward. Offering a description of such a distinction would provide clarity and certainty for DER providers that the general structure of the process would not be subject to marked changes without a thorough process.

23.What is the best method for tracking the value of deferred investments over time? Should they be presented in an attachment to the Grid Needs Assessment, show up as a credit to otherwise-requested budgets in the GRC, or other method?

The GRC would appear to be a logical place for accounting of a cumulative deferred investment to enable discussions of cost recovery to be made within the context of the overall distribution investment budgets and needs assessments. Cost recovery could be evaluated within the larger context of the rate case, including incentives for distribution investment deferrals. (*e.g.*, the Commission should potentially consider allowing recovery of profits on avoided investments to blunt incentives to ignore non-wires alternatives, and could allow a higher rate of "return" on the avoided portion than on investments in order to incentivize greater avoided investments. This would leave utility distribution companies better off when investments are avoided and save ratepayers the value of the avoided investment less allowed return.)

However, timely information on deferred investment value is important for the IDER's mission in development of rates and tariffs, and may be applicable in other proceedings. As such, an annual reporting should be available rather than relying upon a the tri-annual GRC. This may appropriately be attached to the GNA or DPP.

24.Given the existing flexibility to repurpose approved GRC budgets for emergent priorities or changed forecasts, how can the Commission guarantee that distribution investments that are deferred or avoided by DER alternatives actually result in net ratepayer benefits?

In principle, the strongest incentive to provide net ratepayer benefits is to cap rate base reimbursement to ensure that costs in excess of the value of the value to ratepayers is not allowed for recovery, although in practice investment based on forecasts are inherently imperfect. A pay for performance approach can effectively incentivize maximum accuracy and investment.

This issue is not unique to DER investment for deferral, but applies to all investment on behalf of ratepayers. Provided that both DER payments and the actual costs of avoided investment are known and reported, DER incentive payments in lieu of capital investment returns could be disallowed (or clawed back) to ensure that ratepayers receive net benefits for avoided investment.

Respectfully submitted,

Doug Karpa, J.D., Ph.D.
Policy Director
Clean Coalition