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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
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
And Related Matters.	Application 15-07-007 Application 15-07-008

ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING COMMENTS ON POSSIBLE IMPROVEMENTS TO THE 2020 DISTRIBUTION INVESTMENT DEFERRAL FRAMEWORK PROCESS

Summary

Pursuant to the May 7, 2019 Ruling modifying the Distribution Investment Deferral Framework (DIDF) process, this Ruling seeks comments on possible future reforms to the DIDF. Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) provided DIDF reform recommendations in their

2019 Grid Needs Assessment (GNA)/Distribution Deferral Opportunity Report (DDOR) filings.

1. Discussion

A list of questions regarding possible reforms is provided below. Issues and ideas that may require reform in the longer term (*i.e.*, beyond the 2020 DIDF cycle) are identified in Attachment 1. The list of questions below incorporates many of the recommendations from the Independent Professional Engineer (IPE) and proceeding stakeholders. A complete summary of IPE and Investor-owned Utility (IOU) recommendations are provided in Attachments 2 and 3, respectively.

Any changes and/or guidance that the Commission may adopt will apply to the 2020 DIDF cycle and associated Distribution Planning Advisory Group process and Request for Offers (RFO) solicitations. Changes and/or guidance adopted will be in place until the Commission changes the DIDF process either by ruling or decision. Parties should be mindful that not all suggestions for change can be implemented in time for the 2020 DIDF cycle but may be saved and considered for future DIDF cycle improvements. If parties believe that specific DIDF improvements are more appropriate for consideration in the Distribution Resources Plans (DRP) proceeding and subsequent implementation by California Public Utilities Commission (CPUC) Decision instead of Ruling, please provide an explanation in your comments. A guidance ruling on 2020 DIDF changes will be issued in time for IOUs and stakeholders to prepare for the 2020 DIDF cycle.

Opening comments to the questions identified below shall be served and filed by January 17, 2020. Reply comments shall be served and filed by January 31, 2020. Please provide all comments organized using the same item labels and under the same topic areas provided in this Ruling. If none fit, comments under a new heading to be provided by the commenting party will also be accepted.

2. General DIDF Reform Topics

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?
    a. 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?
2. 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.
3. 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.
4. What modifications would increase the likelihood that planned investments that address **voltage, reliability, and resiliency** needs are prioritized for deferral?
    a. Should **reliability and resiliency** needs be **separated** in the 2020 GNA and DDOR filings to allow for consideration of resiliency needs, specifically[1]; and

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[1] The adopted definition of the term, "reliability," pursuant to the Competitive Solicitation Framework (Decision (D.) 16-12-036) includes the term, "resiliency," as follows, "reliability (Back-Tie) services are load-modifying or supply services capable of improving local distribution *reliability and/or resiliency*. Specifically, this service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations." There is also a definition of, "resiliency," in D.16-12-036, which includes the term "reliability." It reads, "resiliency (microgrid) services are load-modifying or supply

b. 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.

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?

6. 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?[2] 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?[3] See also the Pre-Application Project section below.

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services capable of improving local distribution *reliability and/or resiliency*. This service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations."

[2] May 7, 2019 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework.

[3] For example, refer to the Estrella Substation project in PG&E's 2019 GNA/DDOR filing.

7. 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.[4]

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.

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

3. Prioritization Metrics

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?

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

    a. Should SCE's 2019 Excel **prioritization-metrics workbook** be used as the starting template?

    b. What improvements could be made to SCE's Excel workbook of prioritization metrics (*e.g.*, include the complete **Locational Net Benefit Analysis calculations**

[4] For examples, refer to the SCE Alberhill Substation and PG&E Estrella Substation projects in the respective 2019 GNA/DDOR filings.

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.)

12. 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?

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?

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.

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

16. See also Attachment 2, Independent Professional Engineer Recommendations, under this topic area.

4. Pre-Application Projects

17. Should the **existing DIDF approach** be applied to Pre-Application Projects[5] 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?
18. Assuming Pre-Application Projects continue to be included in the GNA/DDOR filings, are **additional DIDF guidelines** and other reforms needed? For example:
    a. Should the projects be identified in the GNA/DDOR filing but not prioritized into Tiers 1 to 3?
    b. 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?
    c. Should the Tier 4 option be eliminated or further defined for the GNA/DDOR filings?
    d. 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?
19. 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?[6]

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[5] The term "pre-application project" refers to transmission and subtransmission projects with associated grid needs under CPUC jurisdiction that are expected to require review pursuant to GO 131-D. Projects filed under GO 131-D typically require review pursuant to the California Environmental Quality Act as well. The following three projects in the 2019 DIDF Cycle were identified that are already undergoing review pursuant to a GO 131-D application process before the CPUC: PG&E's Estrella Substation Project (Application (A.) 17-01-023), SCE's Alberhill Substation Project (A.09-09-022), and SCE's Mira Loma-Jefferson Line Project (A.15-12-007). No projects were identified that are expected to undergo review pursuant to GO 131-D in the future.

[6] For the SCE Alberhill Substation Project, originally filed in 2009 under CPUC Application A.09-09-022, the design and permitting process has cost about $42 million dollars. Excluding

20. 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.)

5. IPE Review Process

21. What modifications to the IPE review process could improve DIDF outcomes? For example:

    a. Improve IOU **data organization** to increase efficiency of the IPE review process; and

    b. Improve IPE **verification and validation**, *e.g.*, increase the number of GNA/DDOR components to be verified and validated.

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

6. Requests for Offers

23. What modifications to the DIDF Advice Letter filing and RFO launch/review process could improve DIDF outcomes? For example:

    a. 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?

    b. What **Competitive Solicitation Framework** reforms are needed to improve DIDF outcomes?

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land costs, which may be recovered through sale to a third party, SCE has incurred approximately $42 million of capital expenditures, including overhead costs, as of December 31, 2018, of which approximately $31 million may not be recoverable if the project is cancelled. Refer to the SCE 2018 Annual Report at pages 17 to 18, available here: http://www.annualreports.com/HostedData/AnnualReports/PDF/NYSE_EIX_2018.pdf.

c. Should **IOU ownership** of DERs be allowed in DIDF RFO procurement? This could occur in a variety of ways:

   i. All DIDF RFOs are **big tent procurements** with no restrictions on which entity can bid and own the DER resource. DER bids are evaluated on a level playing field;

   ii. IOU ownership is allowed, but IOUs do not bid on the RFOs. IOUs may select third-party owned or design-build-transfer projects; and

   iii. IOU ownership of all or part of a potential DER solution is allowed with third-party ownership of the remaining need.

d. 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.[7]

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.?

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

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[7] Refer to the results of SCE's 2013 Preferred Resources Pilot initiated to validate the ability of a portfolio of DERs to meet local-area reliability needs. SCE found, "DER sourcing and deployment can potentially be improved when both competitive solicitations and customer programs are part of the DER sourcing strategy. … Customer programs provided increased speed of delivery." SCE lists location-specific Energy Efficiency marketing and incentive programs as a key example, stating, "this approach enabled SCE to source 74 MW of DERs through customer programs—about 45% more than originally planned" (2019 SCE annual report at https://www.sce.com/sites/default/files/inline-files/2019_PRP_AnnualReport.pdf).

IT IS RULED that:

1. Opening comments shall be filed and served by January 17, 2020.
2. Reply comments shall be filed and served by January 31, 2020.

Dated November 8, 2019, at San Francisco, California.

/s/ ROBERT M. MASON III
Robert M. Mason III
Administrative Law Judge

Attachment 1 (Other Reform Ideas, Possibly Longer Term)
Attachment 2 (Independent Professional Engineer Recommendations)
Attachment 3 (IOU Recommendations in their 2019 GNA/DDOR Filings

ATTACHMENT 1

Other Reform Ideas, Possibly Longer Term

The following comments and questions are provided for longer term consideration and may not be possible to address until after the 2020 DIDF cycle. Note that item numbering is continued from the list of questions in the main body of the Ruling.

26. 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[8] that outlines GNA/DDOR requirements.
27. **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).
28. Identify a select group of planned investments (**case studies**) from the GNA/DDOR filings for the IPE to investigate in greater detail.
29. 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-

[8] May 7, 2019 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework.

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).

30. Please review the **behind-the-meter (BTM) propensity for adoption study** to be posted here https://www.cpuc.ca.gov/environment/info/horizonh2o/estrella/index.html in November/December 2019.[9] Comment on the potential value of similarly scoped study (i.e., case study) or larger-scale study of this kind[10] 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.
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?
32. 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)?[11]

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[9] Notification of the BTM propensity for adoption study's release is expected to be circulated to the R.14-08-013 service list. The study will be an appendix to the March 2019 Draft Alternatives Screening Report for the Estrella Substation and Paso Robles Area Reinforcement Project: https://www.cpuc.ca.gov/environment/info/horizonh2o/estrella/docs/2019-0325%20Estrella_ASR_PublicDraft.pdf. Refer to pages 3-58 to 3-59 of the March 2019 Screening Report.

[10] An example of a larger scale study is the "2025 California Demand Response Potential Study – Charting California's Demand Response Future: Final Report on Phase 2 Results" available at https://drrc.lbl.gov/publications/2025-california-demand-response. The study was based on electricity usage data from about 200,000 customer smart meters in California.

[11] Such projects are already identified in the IOU's quarterly filings pursuant to Assembly Bill (AB) 970 (and Decision D.06-09-003, and hence, the information, including, CPUC filing requirement, cost, in-service date, voltage/capacity, and location, among other details, are already being tracked and may be reasonable to include or cross-reference to the planned investments identified in the DIDF. Although the AB 970 list is for transmission projects, some of the projects have significant distribution components (e.g., PG&E's Estrella Substation Project) that may be appropriate for deferral consideration. Cross checking with the AB 970 reports may also

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? According to GO 131-D, if another agency completes CEQA, the project may meet the GO 131-D criteria for a CPUC Advice Letter approval process instead of a formal application (i.e., a Certificate of Public Convenience and Necessity or a Permit to Construct).

be important for general accuracy. For example, the SCE Alberhill Substation Project in-service date is listed as TBD in SCE's 10/1/19 AB 970 filing but 2024 in their 2019 GNA/DDOR filing.

ATTACHMENT 2

Independent Professional Engineer Recommendations

Independent Professional Engineer (IPE) recommendations are labeled with capital letters.

General DIDF Reform Topics

A. This is the first year that the IOUs were required to report **segment-level needs**. The IOUs took different approaches. Instead of proving a list of all segments in the GNA whether they had a need or not, we recommend only listing segments that have needs to keep data sets manageable. The segment analyses were limited to the first three years of the GNA planning period, and thus, all segment needs were screened out due to the Timing Screen. The utilities should continue to perform these reviews and analysis at the circuit segment level as part of the GNA process such that future, streamlined procurement options can be considered that may differ from the current RFO process.

B. SDG&E's list of substation bank and **circuit level loading and deficiencies** provided in Appendix 2 (Tab "Ruling – Cir-Bank Capacity-Pub" in the Excel workbook) to their GNA/DDOR filing was prior to any newly identified phase balancing, transfer of loads or fixing of modeling discrepancies. It was not possible to know which of the bank/circuit level needs identified by the analysis were addressed using the above-mentioned actions without obtaining additional information from SDG&E. This is an important step in the GNA/DDOR process, since it screens out some needs that may otherwise have to be mitigated by installing new equipment. In the interest of transparency, SDG&E should provide the reasons for removing any of these needs from the GNA in the GNA report filing.[12]

C. The IOUs calculate Locational Net Benefit Analysis (LNBA) values for candidate deferral projects in their DDORs using the **10-year period** as required by the CPUC May 7, 2019 Ruling. However, they do not apply a 10-year period for the calculation of these values (or ranges) in their GNAs. The LNBA values should align between the GNA and DDOR, hence, the GNAs values should apply the same planning periods as the DDORs.

D. All three IOUs proposed projects that include back-tie benefits/needs. We observed that these back-ties are often included in projects that also provide capacity service. The back-tie functions have been proposed to improve reliability and/or resiliency. We also observed that consideration of back-ties is becoming more important to the discussion of projects in the DIDF. In view of the increase in the number of projects with back-tie components or benefits we

[12] See also other issues of this type in the recommendations for SDG&E, IPE report, Section 2.5.

recommend that the IOUs provide **planning standards** documentation that show how they plan for back-ties, including how their planning process evaluates which back-ties are most important in improving customer reliability and how they determine their cost effectiveness. We recommend that the documentation also address planning for reliability and resiliency needs and benefits.

Prioritization Metrics

E. The 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.[13]
F. SCE transitioned to using more **quantitative metrics** in their prioritization process for their 2019 GNA/DDOR filing. Each utility should follow this approach to add additional transparency and help stakeholders understand the basis for project prioritization such that meaningful feedback can be provided. The IOUs should apply the same prioritization process, as much as possible, and strive to use quantified metrics. The IOUs, in this effort, should review the detailed recommendations provided by the IPE in their respective Reports and work together, for example, in a workshop to consider the IPE recommendations regarding metrics such as the use of an LNBA/MWh-day[14] metric.
G. Key assumptions such as discount rate, revenue requirement multiplier, inflation assumptions, O&M factor, and book life are important for calculating **LNBA values**. The IOUs should tabulate these assumptions, as well as provide the sources/basis behind these assumptions in the 2020 GNA/DDOR filings. The IOUs contend that some of this information is confidential. We recommend that it be provided in the IOU confidential filings.
H. The IOUs should consider the impact of **value stacking** on the prioritization metrics and process and discuss modifying their approach for the next GNA/DDOR filings.
I. We observe the importance of key assumptions such as discount rate, revenue requirement multiplier, inflation assumptions, O&M factor and book life on the LNBA values. We recommend that the utilities tabulate the assumptions they used in the LNBA model, as well as provide the sources/basis behind these assumptions in future GNA/DDOR reports.

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[13] Examples of projects where this was an important consideration in this year's DIDF cycle are PG&E's Estrella Project and SCE's Alberhill Project.

[14] The IPE indicated in its reports that it believes this metric is the best of the cost-effective metrics in use. Reasoning is provided in the IPE reports.

J. The **Cost Effectiveness** metric should be given due consideration in the overall prioritization process as a threshold metric in that a DER solution needs to be cost effective to be successful in the bidding process, first and foremost.
K. SCE's implementation of the **Cost Effectiveness** metric has the potential for one component to dominate the other. The LNBA/kW, for example, can dominate the score, giving certain projects a higher overall score than may be warranted when considering that the LNBA/MWhr-year metric is the better of the two SCE metrics per the IPE's report recommendation (see SCE Alessandro Substation Project example and associated IPE review).
L. We appreciated SCE's effort to develop prioritization metrics and LNBA **calculations workbooks**. The other IOUs should consider adopting these templates for the 2020 DIDF cycle.
M. One improvement for SCE's approach is the development of a table to guide **Forecast Certainty** metric scorings for the Likelihood of a Project component because the concept of project certainty is somewhat subjective. The table of guidelines would clarify factors that could delay or accelerate project need. Another potential improvement in SCE's GNA/DDOR filing, is to review the design of the Year of Need and Likelihood of project components of this metric to ensure one does not inadvertently dominate or override the other component.
N. SCE indicated that the Technology Neutral Pro Forma Agreement requires Day Ahead (DA) dispatch of DERs. For projects that have real time needs (event driven) this would require that they be dispatched every day that the event cold occur. This requirement will tend to make DER solutions more expensive and thus less attractive projects for developers. The IOUs should reconsider the **Day Ahead** dispatch requirements such that event driven DER projects are amendable to developer bidding. In general, the number of events experienced in an IOU service territory is low (i.e., five or less in any given year). This Day Ahead reliability requirement not only makes DER solutions less desirable to developers, it also impacts the calculation of prioritization metrics.

Pre-Application Projects

O. DPAG stakeholders would benefit from additional information about the three Pre-Application Projects identified in the 2019 DIDF cycle. The three projects might benefit from further review for Tier 1 consideration that is put on a different timeline than other Tier 1 proposals expected from the IOUs on November 15, 2019.

IPE Review Process

P. IOUs should engage the IPE earlier in the DIDF cycle to allow the work necessary for **verification and validation** to be properly planned and implemented. IPE engagement in May, for example, when IOUs prepare for the Distribution Forecasting Working Group workshop would be a logical timeframe. This workshop provides a forum to vet all the forecasting methodology, input data, and assumptions with stakeholders. Detailed discussions at this time would provide more time for IOUs to prepare their verification and validation walk-throughs with the IPE.

Q. Any **additional local, known loads** should be shared with the California Energy Commission's (CEC) for consideration in the Integrated Energy Policy Report (IEPR) data (e.g., SCE's local known growth projects, or LGPs) if they are not already being shared. Furthermore, the IOUs should include in their GNA/DDOR filings a comparison of the net load forecasts in their previous GNA/DDOR with the actual weather adjusted net load for each circuit for candidate deferral projects. Some IOUs perform such a check already. This will likely be valuable to many stakeholders including the CEC.

R. The GNAs should provide further information regarding **DER-driven needs**, e.g., the required equipment and steps taken by the IOU to develop the non-DER solution as well as the steps planned or taken by the IOU to upgrade monitoring and control systems to allow DERs to meet such needs in the future.

S. The CPUC should work with the **CEC** to ensure that all CEC IEPR data needed by the utilities for GNA/DDOR development be made available to the public so that stakeholders can have access to the data that the IOUs are using in their load forecasting and disaggregation processes.

Requests for Offers

None identified.

ATTACHMENT 3

IOU Recommendations in their 2019 GNA/DDOR Filings

IOU recommendations are labeled with lowercase letters.

General DIDF Reform Topics

a. PG&E: **Customer Count and LNBA information** should only be required for the Candidate Deferral Opportunities (rather than for all Planned Investments), as the purpose of this information is to evaluate the feasibility of DER deferral and it is a significant undertaking to provide this information for all Planned Investments.
b. SCE: Provide **customer composition details** for Candidate Deferral Opportunities only (rather than for all Planned Investments).
c. PG&E: Viability of DER projects that rely on **additional revenue streams** should be further considered, especially if the DER project has not been studied for interconnection and requires charging (acts as a load) from the overloaded circuit.
d. PG&E: **Line sections should be excluded** from future DIDF cycles, as assessing line section needs and documenting the line section Planned Investments requires extensive effort, while few, if any, are likely to be viable Candidate Deferral Opportunities due to the near-term identification of the need, the uncertainty of the long term forecast for line sections, the relatively smaller amount of customers for which to potentially market DERs, and the relatively smaller cost of the traditional mitigation.
e. SCE: Submit GNA/DDOR filings on August 15 annually and publish this content on the IOU **online maps** later, by August 31 annually, because of the addition time required to publish this information in the online portal format, including testing portal functionality after the annual update.
f. SCE: Renewed request regarding the accounting of **contingency planning costs**.[15]

Prioritization Metrics

None identified.

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[15] See May 7, 2019 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process at pages 12 to 13 and Appendix F to August 23, 2019 Amended Reports of Southern California Edison Company (U 338-E) of Its 2019 Grid Needs Assessment and 2019 Distribution Deferral Opportunity Report at pages 3 to 4.

Pre-Application Projects

g. SCE: **Licensing projects** (i.e., projects requiring a GO 131-D application) do not fit within the established DIDF process and should be excluded from the DIDF's Candidate Deferral Project shortlist. SCE proposes, instead that the IOUs evaluate potential DER solutions as part of an internal alternatives analysis and solicitation process prior to filing their GO 131-D project application with the CPUC.

IPE Review Process

None identified.

Requests for Offers

h. PG&E: Renewed request to condense the **DPAG schedule** and generally streamline the DIDF regulatory process to allow for more time for the bidding and RFO process.[16]
i. SCE: Renewed request to **streamline the Competitive Sourcing Framework**.[17]

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[16] PG&E March 2019 Opening Comments on February 25, 2019 Administrative Law Judge's Ruling Requesting Answers to Questions to Improve the Distribution Investment Deferral Framework Process, at pages 3 to 5.

[17] See Joint IOU comments on R.14-10-003 Amended Scoping Memo of Assigned Commissioner and Joint Rulingwith Administrative Law Judge in the Integrated Distributed Energy Resources Proceeding, March 29, 2018, at pages 8 to 11; SCE Utility Regulatory Incentive Mechanism Pilot Report, R.14-10-003, February 4, 2019, at page 15; Comments of Southern California Edison Company (U 338-E) on the Administrative Law Judge's Ruling Requesting Answers to Questions to Improve the Distribution Investment Deferral Framework, March 19, 2019, at page 15.