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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 (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 (U 901-E) 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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JOINT OPENING COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902-M), REGARDING PROPOSED DECISION ON TRACK 3 POLICY ISSUES, SUB-TRACK 1 (GROWTH SCENARIOS) AND SUB-TRACK 3 (DISTRIBUTION INVESTMENT AND DEFERRAL PROCESS)

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JOINT OPENING COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902-M), REGARDING PROPOSED DECISION ON TRACK 3 POLICY ISSUES, SUB-TRACK 1 (GROWTH SCENARIOS) AND SUB-TRACK 3 (DISTRIBUTION INVESTMENT AND DEFERRAL PROCESS)

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I.

INTRODUCTION

Pursuant to Rule 14.3 of the California Public Utilities Commission's ("Commission's") Rules of Practice and Procedure, Southern California Edison Company ("SCE"), San Diego Gas & Electric Company ("SDG&E") and Pacific Gas and Electric Company ("PG&E"), (together, "Joint IOUs"), respectfully submit these comments on the Proposed Decision titled "Decision on Track 3 Policy Issues, Sub-Track 1 (Growth Scenarios) and Sub-Track 3 (Distribution Investment and Deferral Process)" (the "PD").[1]

The Joint IOUs appreciate the important role the distribution grid plays in advancing California's energy policy objectives, including providing opportunities for distributed energy resources ("DERs") via interconnection. For DERs to play a role in supporting the distribution grid, it is critical that the IOUs are assured timely regulatory approval for full cost recovery of all expenditures related to the use of DERs to defer traditional distribution investments. Any risk that such expenditures may not ultimately receive full cost recovery creates significant risk for the IOU selecting a DER instead of a conventional investment for grid services. Further, the IOUs recognize their responsibility to maintain and enhance the safety, security, and reliability of the distribution grid as complexity increases. This responsibility includes contingency planning relating to deferral of deployment of traditional distribution facilities; this key function cannot and should not be delegated to an advisory body. In addition, the IOUs strongly support using competitive solicitations to establish pricing for DER services, but caution that the PD's recommendation to disclose the estimated cost of the conventional solution could obviate the desired benefits of competition and result in unnecessarily high prices targeted at the bid cap.

The Joint IOUs generally support the PD and respectfully recommend the following critical modifications to ensure the success of these new DER regulatory frameworks:

- The PD must be modified to adopt the ratemaking treatment established in Decision ("D.") 16-12-036 without modification. The PD currently alters that treatment by prohibiting cost recovery of DER contract payments. This alteration is problematic because it fails to recognize that DER contract payments during the General Rate Case ("GRC") period may actually be much larger than the GRC revenue requirement for the conventional projects. This alteration also undermines the Rate Case Plan and general ratemaking principles.

- The PD's Distribution Deferral Opportunity Report ("DDOR") content requirements should be modified to permit flexibility and optimization of deferral projects by allowing the IOUs the option to identify an area or region for a need, where appropriate, or a specific location.

- The Grid Needs Assessment ("GNA") and DDOR should align with existing distribution capacity planning studies and not require a five-year power flow analysis on every

[1] Pursuant to Rule 1.8(d) of the Commission's Rules of Practice and Procedure, counsel for PG&E and SDG&E have authorized SCE to file these comments on their behalf.

circuit.

- The scope of "grid needs" that must be included in the GNA and the DDOR should include only the four distribution services adopted by D.16-12-036. It is premature to require inclusion of grid modernization investments and proactive capacity upgrades that are otherwise outside of the normal distribution capacity planning process.

- The GNA should not require identification of "system solutions" as part of the GNA.

- The Joint IOUs respectfully request that the deadline to submit their respective GNAs and DDORs be extended by one month: the GNA would be due June 1 and the DDOR would be due September 1.

- The PD should clarify that the GNA and DDOR filed the year after a GRC is filed are not admissible in that GRC and thus cannot be used to reassess the submitted GRC testimony.

- The PD should be modified to maintain confidential treatment of the estimated costs of conventional projects that are part of deferral solicitations.

- The PD should be modified to eliminate the requirement that a Resolution be issued by the Commission for non-consensus projects, which will create uncertainty and delay in the distribution planning process.

- The PD should be modified to clarify that contingency planning relating to deferral of construction of traditional infrastructure is determined by the IOUs pursuant to their responsibility to operate the distribution grid while maintaining safety and reliability.

- The PD should be modified to allow utility-owned DER solutions to be considered in the Distribution Investment Deferral Framework.

- The PD should be modified to not require the use of the alternate planning scenario for the 2018-19 planning cycle.

- The growth scenarios working group must ensure participation of key subject matter experts when evaluating disaggregation methods.

- The PD should be modified to not require circuit level forecast calibration because it is not practical. Instead, the Commission should direct the IOUs to outline additional data which would be helpful for future disaggregation efforts as part of the upcoming Growth Scenarios Working Group.

- The Joint IOUs request the ability to update forecasts during IEPR years.

II.

DISCUSSION

A. Comments Regarding Sub-track 3

1. The PD Should Adopt the Ratemaking Treatment Adopted in D.16-12-036 Without Modification

The Joint IOUs request that this PD be modified to adopt a ratemaking treatment consistent with the principles for cost recovery established in D.16-12-036. In that decision, the Commission established that the distribution capital expenses deferred by the utilities' Integrated Distributed Energy Resources ("IDER") Incentive Pilots would need to be reviewed and "trued up" in the normal course of the utilities' GRCs, based on the Commission's Rate Case Plan and traditional ratemaking principles for review of utility GRC requests.[2] As the PD acknowledges, in this ratemaking treatment, "neither DER payments nor the avoided costs of traditional investments are reduced from the previously adopted revenue requirement."[3]

The PD alters D.16-12-036's ratemaking treatment by establishing that:

> "[i]n the instance that the Commission approves a DER project to defer a specific investment that has been approved in the most recent GRC and is included in the GRC revenue requirement the utility may recover these costs in the GRC, and may not seek recovery again for the corresponding DER project. Such cost recovery denial only applies through the DER contract period during which the IOU collects a revenue requirement for the approved traditional investment."[4]

The PD appears to make this alteration to support the prohibition on "utilities from recovering costs for the same project more than once (double recovery)." However, a prohibition on recovery of DER contractual payments is not necessary to prevent double recovery. As D.16-12-036 established, the distribution capital expenses deferred by DERs can be included in the IOUs' respective GRCs on a forecast basis, and any previously-authorized distribution capital spending will not be reviewed until the next GRC. As the Commission decided in D.16-12-036, "through the general rate case application process, a utility's past distribution capital spending will be reviewed to ensure that no duplication of

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[2] *See* D.16-12-036, at pp. 60-63.

[3] *See* PD, at Ordering Paragraph No. 2.aa.

[4] *See* PD, at Ordering Paragraph No. 2.z.

recovery of the deferred traditional distribution investment is authorized for inclusion in recorded rate base."[5] Similarly, D.16-12-036 also established that annual DER contract costs are pre-approved and will be recovered over the lifespan of the contract.[6] The PD's prohibition on cost recovery of the DER contract payments during the GRC period intending to avoid double recovery is clearly contradictory to the cost recovery principles adopted in D.16-12-036 and in GRC ratemaking.

In effect, the PD's alteration requires that during the relevant GRC period, DER contract payments are to be made only from the previously adopted GRC revenue requirement for the traditional investment. This alteration is very problematic because it fails to recognize that DER contract payments would need to be included and approved in the prior GRC revenue requirement in order to ensure full cost recovery. DER contract payments may actually be much larger than the GRC revenue requirement for the conventional project because (1) DERs may offer services beyond "distribution attributes" such as energy and capacity, whose cost could exceed the GRC revenue requirement for the deferred project, (2) DER providers may potentially front load costs for the DER solution compared to the conventional solution, (3) depreciation life of a conventional project may be very different than the amortization of the DER solution costs reflected in the DER contract, and (4) the GRC revenue requirement for a conventional project is dependent on a variety of tax-related attributes that are specific to that project.[7]

In addition to distribution attributes, the cost of the non-wires DER solutions may include payments for services such as energy and ancillary services, as well as public policy costs approved in other proceedings, such as the multi-use phase of the Energy Storage proceeding, the IDER proceeding, the Integrated Resource Plan proceeding, and rate design proceedings such as the IOUs' 2018 Rate Design Window proceedings. The costs for these services are not currently included on a forecast basis in the GRC revenue requirement, and therefore must be allowed to be recovered consistent with the Commission's approval of the recovery of the total approved DER costs.[8] If the PD is approved as written, it may effectively prohibit "Deferral RFOs" from soliciting any products or services other than distribution deferral products or services, such as energy, resource adequacy tags, or ancillary services.

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5 *See* D.16-12-036, at p. 60.

6 *See* D.16-12-036, at p. 60.

7 For example, a conventional distribution project can generate a tax credit that reduces the revenue requirement associated with the project in the early years; if this tax credit is large enough, it can result in a *negative* revenue requirement, especially during the GRC period when the project is first approved.

8 In pre-approving the DER contract, the Commission would have already taken the DER costs and benefits into account and concluded that it's in customers' interest to proceed with the DER solution.

This could undermine a utility's ability to maximize DER value, and in conjunction, value to customers and DER providers consistent with California's clean energy policies.

The PD's prohibition of cost recovery for this type of contractual DER payment also appears to ignore a potentially significant discrepancy in the timing of cost recovery of a utility investment versus payment under a third-party DER contract. Contract payments in the earlier years of a DER contract may be much larger than the GRC revenue requirement associated with the deferred distribution investment due to a relatively flat payment structure in a DER contract compared to the conventional solution. This issue is magnified in light of how distribution assets are depreciated versus contract payment structures in DER contracts.

Thus, the PD should be modified to fully align with ratemaking treatment for the forecast costs of DER distribution deferral projects as well as DER contract payments, as intended in D.16-12-036 and GRC ratemaking, including recovery of not only the distribution attributes but also any purchase of appropriate services beyond the distribution attributes. This modification is necessary to avoid inadequate cost recovery and to align with established ratemaking principles. For example, PG&E's 2020 GRC will be filed in 2018, and PG&E intends to include the forecast costs of its conventional and DER distribution deferral projects in its 2018 GRC request consistent with these cost recovery principles. Consistent with D.16-12-036, PG&E will avoid the double cost recovery issue and ensure full cost recovery of its DER deferral projects and the costs of its conventional projects not subject to deferral over the three year 2020- 2022 GRC period.

2. <u>The Grid Needs Assessment and Distribution Deferral Opportunity Report Should Be Modified and/or Clarified to Improve Efficiency and Effectiveness</u>

The Joint IOUs appreciate the Commission's vision for a new distribution planning GNA to provide transparency into the assumptions and results of the distribution capacity planning process for the associated new DDOR, to achieve the objective of maximizing the value and benefits for customers. The Joint IOUs propose the following modifications to improve the efficiency and effectiveness of these new reports.

a) <u>DDOR Content Requirements Should Be Modified to Permit Flexibility and Optimization of Candidate Deferral Projects</u>

The Joint IOUs understand the DDOR is intended to identify, among other things, planned investments that can be deferred by DER solutions providing one or more of the four distribution services adopted by D.16-12-036. However, the Joint IOUs believe the DDOR's reporting requirements should be modified to provide an IOU more flexibility when identifying a planned investment or candidate deferral. Currently, the PD requires each project to align with a specifically identifiable circuit or substation.[9] To operate the grid in a safe and reliable manner, the IOU will frequently reconfigure the grid. Over time, various needs will shift in specific location and timing.

To address this, and ensure the DDOR can more effectively incorporate candidate deferral projects, the Joint IOUs request flexibility to optionally identify investments or candidate deferral projects by small geographic region, where appropriate, or by specific location. Small distribution needs can be aggregated by these geographic regions with proxy mitigations representing potential solutions for this aggregated need area. These geographic regions would be defined as appropriate, most likely consisting of clusters of distribution feeders in close geographic proximity that have an identified need in the five year window. This can facilitate the inclusion of grid needs in later years that are not specifically defined, due to variability and uncertainty, and can be implemented in a relatively short amount of time. The Joint IOUs believe that granting the IOUs this flexibility will enhance the efficiency of the deferral planning process.

b) The GNA and DDOR Should Align with Existing Distribution Planning Processes

The Joint IOUs request that power flow analysis for the GNA be limited to the IOUs' current practices. The GNA appears to require the IOUs to perform power flow analysis on every circuit and develop planning assumption data for every circuit and substation over a five-year forecast horizon.[10] The IOUs do not currently do this. For example, SCE performs power flow analysis on an annual basis, and furthermore, only for some circuits that are selected based upon an identified issue. The IOUs are in the process of developing circuit models to enable ICA calculations which can also be utilized to run power flow analysis. However, even when such models are developed, the IOUs recognize that forecast uncertainty increases with time and the identification of needs and specific projects will change from year to year. Thus, requiring a five-year analysis on every circuit will require significant additional resources and time.

The GNA and DDOR are new deliverables of the planning process that require new calculations and data never before developed in a report form. Rather than impose new planning requirements on the

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[9] *See* PD, at pp. 35-36.

[10] *See* PD, at pp. 33-34.

IOUs such as performing power flow analysis on every circuit, the Commission and IOUs should focus on the contents of the GNA and DDOR to provide transparency based on current practices, taking into account the current limitations while exploring steps to improve providing relevant information. Based on experience and feedback from the Commission and stakeholders, the Joint IOUs believe the planning requirements for the GNA and DDOR can be revisited as planning methodologies and software continue to improve and if it appears an expansion of this analysis is needed.

Similarly, the PD requires the Joint IOUs to include in the DDOR information that would inform solicitation activities such as: season needed, day(s) needed, and range of expected exceedances/year. This information is currently not developed in the IOUs' distribution planning process. Whereas such information will be developed to inform eventual solicitations of projects selected for deferral, it is burdensome to develop and provide this information for every candidate deferral projects in the DDOR. Existing planning software capabilities do not produce this information in reports and require significant analysis to develop. Future planning tools are being developed to meet these needs, however, they do not exist at present. Therefore, the IOUs request that the PD be modified to remove this requirement from the DDOR as it will be eventually developed for projects that move forward to solicitation, and recommend that this topic be revisited as the planning methodology and software improve.

c) **Grid Needs Should Be Limited At This Time to the Needs That Align with the Categories Identified in D.16-12-036**

The PD does not define the scope of the "grid needs" that must be included in the GNA and the DDOR. However, the PD appears to identify three categories of "grid needs" to be included in the report: (1) the four distribution services adopted by D.16-12-036, (2) grid modernization investments, and (3) proactive hosting capacity upgrades proposed to accommodate forecast autonomous DER growth.

The Joint IOUs understand the GNA is intended to provide transparency into the assumptions and results that yield the candidate deferral shortlist that arises out of the DDOR.[11] Accordingly, the Joint IOUs recommend that "grid needs" for the GNA and DDOR be limited to the four distribution services that were adopted by D.16-12-036 and required to be included as part of the DDOR. While the PD envisions the GNA and DDOR will ultimately support proposed grid modernization investments and proactive capacity upgrades, the IOUs believe that it is premature to require inclusion of such needs, to

[11] *See* PD, at p. 32.

the extent they are outside of the normal planning process. The Commission is still developing the grid modernization policy framework to define and structure those needs, and this policy framework was not included as part of this PD. In addition, the development of proactive hosting capacity upgrades depends upon how the Integration Capacity Analysis ("ICA") can be used in the planning process, which is a policy topic that is still being worked on in the ICA long term refinements working group.

d) The GNA Should Not Include System Solutions

For each grid need, the PD requires the GNA identify the need's substation, circuit and/or facility identification. However, this requirement states that identification must include "the location and system resolution of grid need." The Joint IOUs request that this bullet be modified to clarify that it is focused upon the location of the need and not any description of the system solution. The purpose of the GNA is to identify the locations of grid needs specifically, not the solutions to those needs. System solutions should be reserved for the DDOR and DPAG process.

e) The GNA Should Be Due June 1 and DDOR Should Be Due September 1

The Joint IOUs respectfully request that the deadline to submit their respective GNAs and DDORs be extended by one month: the GNA would be due June 1 and the DDOR would be due September 1.[12] This will permit the GNA to more closely align with the IOUs' respective planning processes.

The Joint IOUs also request that the deadline for the DDOR not reflect the deadline for initial system wide implementation of the Locational Net Benefits Methodology ("LNBA") deferral and heat map use case. Significant updates to software are required to publish LNBA values via the data access portal and to train staff to complete the LNBA analysis. Future updates to LNBA can align with the DDOR; however, due dates for initial implementation of LNBA should reflect each of the IOUs' work plans filed to the commission on November 6, 2017 as required by Track 1 decision D.17-09-026.

In addition, the Joint IOUs respectfully request the opportunity to file Tier 1 Advice Letters to modify these deadlines in the future, if they determine a change is necessary in light of the experience they gain developing these reports.

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[12] The Joint IOUs note that, given the dynamic nature of the grid and grid needs, proposed solutions may change. If such changes occur after the submission of a DDOR, the Joint IOUs will bring these changes to the attention of the DPAG when the proposed solution is being discussed. Such changes may also occur after the submission of the Tier 2 Advice Letter that is filed at the conclusion of the DPAG process. If changes occur to a deferrable solution after the submission of the Tier 2 Advice Letter, the Joint IOUs will file an update/supplement to that Advice Letter.

f) The PD Should Clarify the GNA and DDOR Filed the Year After a GRC Year May Not Be Used in the GRC

The PD states that "the GNA and DDOR filed the year after a GRC year may not be used to update the underpinning assumptions of GRC testimony that was filed the previous year."[13] The Joint IOUs understand this to mean that the GNA or DDOR filed the year after a GRC year is not admissible in that GRC and thus cannot be used to reassess the submitted GRC testimony. This is consistent with the Commission's stated rationale, that "[t]he information contained in the GNA and DDOR are snapshots in time . . . [and introduction of such a GNA and DDOR into the GRC] would introduce a significant new variable into the complex GRC process."[14] The Joint IOUs respectfully request that the PD be modified to confirm the Joint IOUs' understanding.

3. The PD Should Be Modified to Maintain Confidential Treatment of the Estimated Costs of the Conventional Projects That Are Part of a Deferral Solicitation

Maintaining the confidentiality of market-sensitive information from market participants helps to prevent developers from manipulating the market to the detriment of customers.[15] The PD should be modified to maintain confidential treatment of the estimated costs of the conventional projects and cost caps that are or will be part of a solicitation, to prevent manipulation of the procurement process and markets.[16] The PD concludes that while "the risk of market manipulation could result in suboptimal outcomes for ratepayers," this risk does not outweigh the benefits of disclosure such as a more "clear and predictable market signal to DER providers" to determine whether they can participate in a solicitation.[17] The Joint IOUs urge the Commission not to concede to suboptimal outcomes, which undermines the DRP's overarching goal to maximize benefits and values of DERs for customers.

The PD notes its conclusion is based, in part, upon a concern about the development of the LNBA DERAC use case.[18] This concern is misplaced. Confidential treatment of estimated costs of the

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[13] *See* PD, at Ordering Paragraph No. 2.i.

[14] *See* PD, at p. 37.

[15] The Joint IOUs have provided detailed support for this position in their submissions in this proceeding and the IDER proceeding that they will not repeat here.

[16] Although the PD characterizes these costs as "actual costs," they are merely estimated costs. The Joint IOUs caution that the DDOR unit cost will likely change as it becomes more refined concurrent to the DPAG process.

[17] *See* PD, at p. 57.

[18] *See* PD, at p. 58.

conventional projects that are or will be the subject of active solicitations is distinct from the use case. The PD also notes that distribution upgrade cost information is not deemed confidential in a utility's GRC and that interconnection unit cost guides are not confidential.[19] These facts are not applicable because the context in which those costs are provided is fundamentally different than the costs at issue here, because those costs are not the subject of active competitive solicitations.

If the PD does not maintain the confidential treatment of these estimated costs, then the IOUs request that the Commission formally revisit this determination at the completion of the first round of solicitations pursuant to DIDF and/or when requested by a utility for a specific DER distribution deferral project prior to issuance of a solicitation for that project. While the PD directs the IOUs and Commission staff to monitor procurement activity and make recommendations for modifications in light of activity they observe during the solicitations,[20] any mandate to publically disclose this information must also be formally reviewed after gaining experience with its application to specific RFOs, including RFOs exempted from the requirement when requested by a utility.[21] In addition, the Joint IOUs should be permitted to update these cost estimates at the time an RFO Advice Letter is submitted and prior to the submission of bids, in order to accurately represent up to date cost information, consistent with the process established in Resolution E-4889.[22]

4. The Commission Should Eliminate the Resolution on Non-Consensus Projects, Which Will Create Uncertainty and Delay in the Distribution Planning Process

The Commission should eliminate the requirement for the Commission to issue a resolution to deal with Non-Consensus Projects after the DPAG process, which will create uncertainty and delay in the distribution planning process.[23] Non-consensus projects should not be required to go out for solicitation. The PD currently permits the Independent Professional Engineer to submit a DPAG Report that includes "stakeholder feedback regarding candidate projects that the IOUs did not propose [in their Advice Letter] for solicitation [and] [t]he Commission may then rule on these non-consensus projects in

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[19] *See* PD, at p. 58.

[20] *See* PD, at p. 57.

[21] The PD's proposed disclosure requirements appropriately do not apply to market-sensitive energy procurement data protected from disclosure pursuant to D.06-06-066 and other confidentiality rules and decisions applicable to the IOUs' energy procurement plans.

[22] *See* Resolution E-4889, at Ordering Paragraph No. 12.

[23] *See* PD, at Ordering Paragraph No. 2.v.

a resolution."[24] The addition of such a backstop "catch-all" for non-consensus projects will undermine the effectiveness of this new deferral process by adding additional steps and uncertainty to an already aggressive review process for deferral solicitations that could cause delays in installing the necessary solutions required to maintain a safe and reliable grid and adversely affect the marketplace. Delaying installation of solutions could cause equipment to exceed capacity limits resulting in potential damage, outages or unsafe conditions. If there is concern that this deferral process will not be sufficient to adequately prioritize and incorporate all deferrable projects, the focus should remain on refining and improving those processes as experience and data are gained.

5. <u>DPAG Must Not "Determine" Contingency Plans</u>

The PD should be modified to clarify that contingency planning related to deferral of traditional infrastructure investment is determined by the IOUs pursuant to their responsibility to maintain safety and reliability. The PD currently states that "contingency planning shall not be prescribed but rather determined by the DPAG on a case-by-case basis."[25] Consistent with the PD's overall discussion concerning the role of the DPAG, the DPAG's role should be limited to providing advice and recommendations.[26] As established by the PD, the IOUs will present their DDOR to the DPAG and engage in a review and consensus-building process that culminates in an IOU's filing of an Advice Letter that "include preliminary contingency plans."[27] The Joint IOUs agree that contingency plans are an appropriate advisory topic for the DPAG, and the Joint IOUs support the development of contingency principles that can serve as guidelines for contingency implementation. But, the IOUs' core responsibility is ensuring safe and reliable service and thus they must retain the flexibility and control over contingency planning.[28] If a DER contract fails or an unexpected need occurs on the distribution system that requires immediate mitigation to prevent outage conditions, relying on the DPAG to

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[24] *See* PD, at p. 64.
[25] *See* PD, at Ordering Paragraph No. 2.w.
[26] *See* PD, at pp. 60-64 ("[W]e affirm that the DPAG is to advise the IOUs.").
[27] *See* PD, at p. 64.
[28] The Commission recently acknowledged this in its Resolution approving the start of the Competitive Solicitation Framework Incentive Pilot, stating: "If a contingency were to occur during the solicitation process, the Commission expects the Utilities to consult with the Independent Evaluator and include reasons for the contingency in their report to the PRG. The utilities are ultimately responsible for ensuring safe and reliable service so that if the contingency were to occur during the deployment and operations phase then the utilities should enforce the contingency mitigations in accordance with the terms of their contracts." Resolution E-4889, at p. 31. *See also* D.99-10-065, at p. 16; D.03-02-068, at p. 13.

determine contingency plans could result in damage to equipment and/or prolonged outages and/or unsafe conditions. These scenarios could compromise public safety and reliability of the electric grid.

6. <u>DIDF Should Include Third-Party and Utility-Owned DERs</u>

The PD should be modified to clarify that the Distribution Investment Deferral Framework ("DIDF") does not preclude utility-owned DERs as potential solutions to meet IOU distribution needs in a cost-effective manner. The DRP demonstration projects permitted both third-party and utility-owned DERs to participate, to test the viability and cost-effectiveness of multiple structures.[29] The IOUs request that the DIDF similarly permit utility-owned DER solutions to be included in DIDF solicitations.

B. <u>Comments Regarding Sub-track 1</u>

1. <u>The PD Should Not Require Use of the Alternate Planning Scenario for the 2018-19 Planning Cycle</u>

The Joint IOUs believe the PD must be modified to acknowledge that the "alternate planning scenario" will not be ready for the 2018-19 planning cycle. It is not clear when it could be ready. The PD's Ordering Paragraph No. 1.c states that the "IOUs shall develop the alternate planning scenario . . . for the 2018-19 distribution planning cycle." The Joint IOUs understand that this planning scenario relies upon the Distributed Energy Resources Avoided Cost Calculator ("DERAC") use case.[30] There remain significant challenges associated with developing an accurate and effective methodology for the scenario—particularly in light of the need to determine avoided costs based upon a counterfactual demand forecast that assumes no "autonomous" growth of DERs. While the Joint IOUs will strive to address those challenges to support the objectives the Commission has identified for the new use case, the Joint IOUs are concerned the planning scenario is not ready or viable, and they will not have the resources or planning capabilities to preform multiple planning scenarios in the 2018-19 cycle.

This use case and its methodology are not yet approved by the Commission. The IOUs each submitted their respective proposals on December 5, 2017, and the Commission's review remains pending. The Joint IOUs' respective December 2017 LNBA proposals represent a high-level overview

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[29] *See* D.17-02-007. The Joint IOUs also note that the Commission's DER Action Plan contemplated evaluation of utility-owned DERs. *See* California's Distributed Energy Resources Action Plan: Aligning Vision and Action, May 3, 2017, at Vision Element 2.C and Action Element 2.12.

[30] *See* PD, at p. 20 ("The Track 1 decision (D.17-09-026) adopted a use case for the Locational Net Benefits Analysis (LNBA) that would require an alternate DER forecasting scenario: determining the cost and benefits to the distribution grid of 'autonomous' DER growth, *i.e.*, that which is reasonably expected to occur under existing ratepayer-funded tariffs and programs.").

of frameworks and methodologies that may be developed to successfully implement the DERAC use case. These proposals still require significant additional dialogue and development. For example, SCE's proposal recommended that the CEC develop the counterfactual 30-year forecast that removes "autonomous" DER growth, consistent with CPUC policy that distribution planning should, at least as a starting point, begin with forecasts developed by the CEC. SCE cannot begin the counterfactual planning analysis until the counterfactual forecast is produced. If the CEC is not going to provide the counterfactual forecast, it will take a significant effort involving many stakeholders to develop and get approval for a counterfactual forecast, which must be completed before the planning analysis can begin. Accordingly, the Joint IOUs believe the Commission should not specifically require that the alternate planning scenario be used for the 2018-19 distribution planning cycle.

2. Working Group Participation from Subject Matter Experts Is Critical to Meaningfully Evaluate Disaggregation Methodologies and Identify Best Practices

The PD establishes that the IOUs must "vet disaggregation methods through the Growth Scenario Working Group and incorporate best practices in their planning processes."[31] Disaggregation is a highly complex technical activity due to data granularity, customer behavior, and market dynamics. Meaningful discussion requires a substantial amount of understanding of modeling techniques and best practices in forecasting. Therefore, to have a robust, objective "vetting" of disaggregation approaches and the identification of best practices, it is essential to have participation from subject matter experts from CEC, CAISO, as well as industry/academia. The Joint IOUs respectfully request the PD be modified to specifically note that such expertise will be required.

3. "Calibration" Is Not Practical with Currently Available Data

Ordering Paragraph No. 1.f and Section 2.3 of the PD direct the IOUs to "calibrate their circuit-level forecasts based on actual data." The Joint IOUs support the Commission's goal of incorporating actual data to improve disaggregation. However, actual "calibration" is not reasonably achieved with the existing limited adoption history, the lack of data availability for some DERs at the circuit level,[32] and actual grid data provided by equipment such as line sensors that need to be further deployed. Further, once that actual data is identified and acquired, a longer history—at least 3 to 5 years—of historical forecast performance is needed to be able to demonstrate improvements in model accuracy.

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[31] *See* PD, at Ordering Paragraph No. 1.d.

[32] As another example, circuit level Energy Efficiency savings are recorded for only downstream program installed savings, and not available for codes and standards or upstream programs.

Therefore, circuit level forecast calibration is not practical at this time. Instead, the Commission should direct the IOUs to outline additional data which would be helpful for future disaggregation efforts as part of the upcoming Growth Scenarios Working Group.

4. The Joint IOUs Request the Ability to Update Forecasts During IEPR Years

In Ordering Paragraph No. 1.b and Section 2.1 of the PD, the Commission discusses the need to update system level DER forecasts in IEPR off-years. The Joint IOUs support the Commission's efforts to enable the use of a more recent forecast for distribution planning. The Joint IOUs request the Commission modify this section to afford IOUs the ability to update DER forecasts and to propose system level adjustments on an annual basis to the extent there is a significant impact from changing market conditions or policies at the state or federal level after adoption of the IEPR, via a Tier 2 Advice Letter to be filed no later than October 1 of a given year.

III.
CONCLUSION

The Joint IOUs appreciate the opportunity to provide these comments to the PD.

Respectfully submitted,

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On Behalf of the Joint Parties: Southern California Edison Company (U 338-E); San Diego Gas & Electric Company (U 902-M); and Pacific Gas and Electric Company (U 39-E)

Dated: January 8, 2018

Appendix A

Proposed Revisions to Findings of Fact, Conclusions of Law, and Ordering Paragraphs Pursuant to Rule 14.3(b)

Conclusions of Law

6. It is reasonable to conclude that the ***estimated costs of conventional projects that are part of deferral solicitations shall be considered confidential market sensitive information***. ~~**actual cost of distribution system upgrades shall be considered public information as part of the ongoing DIDF, and in associated DRP tools such as the Locational Net Benefits Analysis. It is reasonable to distinguish this conclusion from the conclusions reached in D.16-12-036 based on a closer examination of the applicability of the confidentiality provisions adopted in D.06-06-066 to the types of information at issue in the ongoing DIDF.**~~

~~**7. The confidentiality provisions adopted in D.06-06-066 were motivated by the experience of the Energy Crisis. In the case of the DIDF, it would be premature to rule that disclosing a solicitation's price ceiling has an equal effect as disclosing the market prices in a solicitation.**~~

Ordering Paragraphs

(Page 17/Ordering Paragraph 1.b)

1.b. If ~~**annual**~~ updates to the California Energy Commission forecasts for photovoltaic, electric vehicle, and energy storage are ***necessary*** ~~**not feasible**~~, each year the IOUs are authorized to propose system-level adjustments via Tier 2 Advice Letter.

~~**1.c. The IOUs shall develop the alternate planning scenario that will enable them to assess costs and benefits of DER grid integration, as ordered in Decision (D.) 17-09-026, for the 2018-19 distribution planning cycle**~~.

1.f. The Commission orders the IOUs to ***outline, as part of the upcoming Growth Scenarios Working Group, additional data that would be helpful for future disaggregation efforts.*** ~~**evaluate the effectiveness of past forecasts and calibrate their circuit-level DER forecasts based on actual data.**~~

1.g . . . Commission Staff will be responsible for establishing the working group schedule, defining necessary outcomes deliverables for the Working Group***, ensuring a sufficient level of participation from academic/industry subject matter experts***, and ensuring that the meeting agendas will meet these outcomes. . . .

2.d. The IOUs shall file, in reports pursuant to this Decision, a Grid Needs Assessment (GNA) by ***June 1*** ~~**May 1**~~ of each year, and a Distribution Deferral Opportunity Report (DDOR) by ***September 1*** ~~**August 1**~~ of each year.

2.i. The Commission orders that the GNA and DDOR filed the year after a GRC year may not be used to update the underpinning assumptions of GRC testimony that was filed the previous year ***and will not be admissible in that GRC***.

2.j. The Commission orders DIDF reporting requirements to be implemented for each year going forward:

3. GNA due ***June 1*** ~~**May 1**~~. In 2018 IOUs shall provide data available,
and provide full GNA in 2019;
4. DDOR due ***September 1*** ~~**August 1**~~.

2.q. ***The estimated costs of conventional projects that are part of deferral solicitations shall be considered confidential market sensitive information.*** ~~**The Commission orders the actual cost of distribution system upgrades to be considered public information as part of the ongoing DIDF, and in associated DRP tools such as the LNBA. We distinguish this conclusion from the conclusions reached in D.16-12-036 based on a closer examination of the applicability of the confidentiality provisions adopted in D.06-06-066 to the types of information at issue in the ongoing DIDF**~~**.**

2.u. The Commission orders the IOUs to initiate DPAG meetings by ***September*** ~~**August**~~ 15 of each year, two weeks following the IOUs' annual DDOR filing. The DPAG will then have six weeks to complete its review process.

2.v. The Commission orders the IOUs to file a Tier 2 Advice Letter at the conclusion of the DPAG process, by November ***15*** ~~**1**~~ each year, recommending the distribution deferral projects that should go immediately out for solicitation via the Competitive Solicitation Framework (CSF) Request for Offer (RFO). These advice letters shall include preliminary contingency plans, developed to the guidance provided in Section 3.7.4., as well as the IPE's DPAG Report, as attachments. The IPE's DPAG Report will put forth his or her evaluation of the DPAG review process, plus any stakeholder feedback regarding candidate projects that the IOUs did not propose for solicitation. ~~**The Commission may then rule on these non-consensus projects in a resolution.**~~

2.w. The Commission orders that contingency planning shall not be prescribed but rather determined by the ***IOUs*** ~~**DPAG**~~ on a case-by-case basis***, subject to advice from the DPAG***. ***Contingency planning is an appropriate topic for advice by the DPAG.***

2.z. For the cost recovery of DER service contracts, the Commission orders the IOUs to track DER payments in the existing IDER Incentives Pilot balancing accounts, which shall be repurposed as distribution deferral payment balancing accounts. However, we prohibit utilities from recovering costs for the same project more than once (double recovery). ***The IOUs will receive full recovery of the costs of the procured DER solutions, including those entered into between rate cases, and consistent with D.16-12-036, the IOUs can recommend an allocation in their respective next GRCs of costs of existing or new projects to be recovered in their GRC applications or via other cost recovery applications.*** ~~***or***~~ ~~**In the instance that the Commission approves a DER project to defer a specific investment that has been approved in the most recent GRC and is included in the GRC revenue requirement the utility may recover these costs in the GRC, and may not seek recovery again for the corresponding DER project. Such cost recovery denial only applies through the DER contract period during which the IOU collects a revenue requirement for the approved traditional investment.**~~