COM/MP6/jt2 **Date of Issuance 2/15/2018**

Decision 18-02-004 February 8, 2018

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

DECISION ON TRACK 3 POLICY ISSUES, SUB-TRACK 1 (GROWTH SCENARIOS) AND SUB-TRACK 3 (DISTRIBUTION INVESTMENT AND DEFERRAL PROCESS)

Table of Contents

Table of Contents (cont.)

DECISION ON TRACK 3 POLICY ISSUES, SUB-TRACK 1 (GROWTH SCENARIOS) AND SUB-TRACK 3 (DISTRIBUTION INVESTMENT AND DEFERRAL PROCESS)

Summary

This decision addresses the issues identified in Track 3, Sub-track 1 (Growth Scenarios) and Sub-track 3 (Distribution Investment and Deferral Process) as follows:

1. **With respect to Track 3, Sub-track 1: Growth Scenarios**
   a. The Integrated Energy Policy Report (IEPR) demand forecast will be adopted with updated Distributed Energy Resources (DER) forecasts in January 2018. The Commission orders the Investor-Owned Utilities (IOUs) to use these forecasts for their 2018-19 distribution planning cycle.

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

   c. The IOUs shall vet disaggregation methods through the Growth Scenario Working Group and incorporate best practices in their planning processes.

   d. The Commission orders the IOUs to work with California Independent System Operator (CAISO) to ensure that there is agreement on DER forecast disaggregation.

   e. The Commission orders the IOUs to evaluate the effectiveness of past forecasts and calibrate their circuit-level DER forecasts based on actual data.

   f. The Commission directs Commission Staff to develop a process and schedule for resolving the issues discussed in this decision through the Growth Scenarios Working Group. We order parties to file comments within two weeks of the issuance date of this decision recommending scoping issues for the next iteration of the Growth Scenarios Working Group. Comments should be no longer than ten pages in

length and should, at a minimum, suggest specific scoping questions for the two main unresolved issues discussed in this decision: DER forecast disaggregation methodologies, and using DER growth scenarios for policy planning purposes. The Commission will then set the Working Group's scope and schedule in a subsequent ruling, and expects to rule on Working Group issues in a subsequent ruling. Commission Staff will be responsible for establishing the working group schedule, defining necessary outcomes and deliverables for the Working Group, and ensuring that the meeting agendas will meet these outcomes. The IOUs shall contract with a facilitator to coordinate agenda setting, manage the Working Group meetings, and prepare a progress report to be submitted on June 15, 2018.

2. **With respect to Track 3, Sub-track 3: Distribution Investment Deferral Framework (DIDF)**

    a. The Commission directs the IOUs to implement DER growth scenarios and the Integration Capacity Analysis (ICA) for purposes of the existing distribution planning and new Distribution Resources Planning (DRP) processes as described in Section 3.3 of this decision and as visualized in Figure 2 of this decision.

    b. The ICA, for the planning use case, is a tool that the IOUs must use alongside traditional planning tools and methods in completing the annual planning exercise.

    c. The Commission orders the IOUs to apply DER growth scenarios to load and operational profiles in traditional planning tools consistent to their application in the ICA.

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

    e. The GNA and DDOR shall provide a characterization of circuits according to the data types and attributes described in Section 3.4.1. of this decision. GNA and DDOR data shall be made available in map form, as a pop-up layer atop the circuit models being developed for the ICA, and in downloadable, machine-readable datasets.

f. Parties may file comments within 30 days of GNA submissions in order to provide initial feedback on GNA data in advance of the Distribution Planning Advisory Group, and to make recommendations for how the GNA might be improved for future filings. These comments shall be filed in the DRP proceeding or its successor.

g. The IOUs shall file a Tier 2 advice letter 60 days following the issuance date of this Decision proposing DRP data redaction criteria that work to ensure the physical and cyber security of the electric system and reflect the customer privacy provisions established in Decision (D.) 14-05-016.

h. The information each IOU presents in its GRC testimony shall be consistent with that which the IOU presents in that year's GNA and DDOR reports. However, we affirm the IOU's ability to update any aspect of its GRC testimony due to emergent needs or changing forecasts that arise following that year's GNA and DDOR filings. The IOUs must explain any discrepancies between the GNA and DDOR reports and GRC testimony within the GRC testimony.

i. The Commission orders that the GNA and DDOR filed the year after a GRC filing year is inadmissible in the evidentiary record of that GRC proceeding, and may not be used to update the underpinning assumptions of GRC testimony that was filed the previous year.

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

    1. GNA due June 1. In 2018 IOUs shall provide data available, and provide full GNA in 2019 ;

    2. DDOR due September 1.

k. The Commission orders the IOUs to propose work plans by which they will develop and implement the data compilation and reporting capabilities needed to complete the annual GNA and DDOR exercise, including a high-level description of the steps necessary to develop such internal capabilities and estimated interim milestones. The Commission further orders the IOUs to propose formats for the GNA and DDOR datasets based on the requirements laid out in Section 3.4.1 of this decision. The IOUs may include in these proposals the most effective representations of the data attributes listed in Section 3.4.1. Both proposals shall be filed in a Tier 3 advice letter within 60 days of the issuance of this Decision. The Commission's Energy Division may at its discretion convene a workshop to review the IOUs' proposed formats in order to source stakeholder feedback on the user-friendliness and data presentation effectiveness, in advance of a Resolution on the matter.

l. The Commission orders the IOUs to develop a central DRP data access portal, by which users can click between tabs to view ICA, LNBA, GNA, and DDOR data on the circuit map, and can query and export data in tabular form based on a geographic search or keyword search. Data portals shall also have Application Programming Interface (API) capability that would allow users to access data in a functional format from back-end servers in bulk.

m. The Commission orders the IOUs to propose a work plan for implementing the DRP data access portal within 90 days of the issuance of this Decision. The IOUs' proposed work plans shall be filed in a Tier 3 Advice Letter, include a high-level description of the steps necessary to develop the data access portal, and propose estimated interim milestones and a deadline for implementation based on those steps. The Commission's Energy Division may at its discretion host a workshop to discuss the format and function of the DRP data access portals. The Commission will then rule on the IOUs' proposed deadline in a resolution.

n. The Commission authorizes the IOUs to establish a memorandum account to track the incremental costs of implementing the GNA, DDOR, and Data Access Portal to the specifications described in this decision. The IOUs shall create a sub-account within the memorandum account established in D.17-09-026 to track the incremental costs of ICA and Locational Net Benefits Analysis (LNBA) implementation for this purpose. The IOUs shall file a Tier 1 advice letter within 30 days of the issuance date of this decision to propose establishment of this memorandum account.

o. The Commission adopts Timing and Technical screens for use in the initial deferral screening process.

p. The Commission adopts Cost-Effectiveness, Forecast Certainty, and Market Assessment metrics to characterize and help prioritize projects on the candidate deferral shortlist. We decline to prescribe specific methodologies by which these metrics should be implemented in the initial roll-out of the DIDF, and instead direct the IOUs to apply these metrics according to their own approaches. We do emphasize that the overarching goal of DIDF is that any candidate deferral project that can be cost-effectively deferred through DERs should be deferred.

q. 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 Locational Net Benefits Analysis (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. We affirm that the IOUs may update the avoided cost value in their Tier 2 advice letter requesting approval to launch an RFO, described in Section 3.7.3, based on the most up-to-date cost assumptions. The IOUs shall explain the drivers of such a change in the advice letter.

r. The Commission orders that the IOUs shall adhere to existing rules and regulations pertaining to the types of data they share with the Distribution Planning Advisory Group (DPAG), including customer privacy provisions established by D.14-05-016. If the IOUs believe market participants should be excluded from discussions of certain data types they feel should remain confidential, the IOUs shall propose and provide the legal rationale for establishing non-market-sensitive and market-sensitive portions of the DPAG according to the agenda-setting process described in Section 3.7.3. of this decision.

s. The Commission establishes the DPAG to consist of IOUs, Commission technical staff, an Independent Professional Engineer (IPE) technical consultant, non-market participants, and DER market providers.

t. The Commission orders that the IOUs, in their annual DDOR filing, shall include a proposed DPAG workplan and agenda for the DPAG process. Parties may then provide comments on the proposed agenda within one week, followed by a letter from the Director of the Commission's Energy Division establishing the final agenda within two weeks.

u. The IOUs' proposed DPAG agendas shall, at a minimum, encompass a review of: 1) planning assumptions and grid needs reported in the GNA; 2) planned investments and candidate deferral opportunities reported in the DDOR; and 3) candidate deferral prioritization. Importantly, as part of the discussion on candidate deferral opportunities, the IOUs shall present the underlying technical and operational requirements that a given DER alternative must provide in order to successfully meet the underlying grid need.

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

w. The Commission orders the IOUs to file a Tier 2 Advice Letter at the conclusion of the DPAG process, by December 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 separate resolution from that which disposes of consensus projects.

x. The Commission orders that contingency planning shall not be prescribed but rather determined by the IOUs on a case-by-case basis. The IOUs shall present proposed contingency plans for candidate deferral projects for review and feedback within the DPAG, which can help hone the contingency plans the IOUs file in their Tier 2 advice letter as described in Section 3.7.3.

y. The Commission orders the IOUs to launch the CSF RFO within thirty days of the Commission's disposition of the Tier 2 Advice Letter requesting approval of distribution deferral projects. Before issuing the RFO, the IOUs shall present their draft solicitation materials with the Commission's Energy Division staff.

z. Future IDER policy determinations including potential continuation of an incentive mechanism and refinements to the CSF such as methodologies for incrementality, double counting, technology neutral pro forma contracts, and technical performance requirements shall apply to the DIDF.

aa. We agree to continue the ratemaking treatment adopted in D.16-12-036, wherein the IOUs shall track DER contract payments in the existing IDER Incentives Pilot balancing accounts—which shall be repurposed as Distribution Deferral balancing accounts—for recovery in the GRC, and DER incentive payments tracked in a balancing account for recovery in ERRA. We further affirm that neither DER payments nor the avoided costs of traditional investments shall be reduced from the previously adopted revenue requirement. We clarify that this ratemaking treatment does not preclude the Commission's ability to reduce an IOU's revenue requirement request in an open GRC application in the instance where an IOU includes a specific project in its distribution capital request, while at the same time that project is being considered as a candidate deferral project.

bb. We prohibit utilities from recovering costs for the same project more than once (double recovery). In the instance that the Commission approves a DER project to defer a specific investment that has been explicitly approved in the most recent GRC and is included in the GRC revenue requirement, the utility may recover these costs through GRC revenues, and may not book payments for the corresponding DER project to the Distribution Deferral balancing account. Such cost recovery denial only applies through the DER contract period during which the IOU collects a revenue requirement for the approved traditional investment.

cc. The IOUs shall book DER payments for ancillary services such as energy and Resource Adequacy to the ERRA account, similar to other types of procurement costs.

dd. The Commission orders the IOUs to file confidential reports to the Commission containing itemized data on payments made to contracted DER projects versus the estimated traditional spending such deferral projects were able to avoid. The IOUs may compute such estimates based on unit costs and typical depreciation schedules for given asset types. These reports will be due concurrently with an IOU's DDOR submission in its GRC filing years.

ee. If the IOUs demonstrate to the Commission in their confidential DER payment reports that a DER project is more expensive than an explicitly-approved traditional project due to differences in depreciation schedules versus DER contract payments, the IOUs may file a Tier 2 advice letter requesting that the outstanding differential be added to the Distribution Deferral balancing account for recovery within that year's GRC application.

ff. The Commission orders the establishment of a distribution capital per customer metric, which shall be calculated in each IOUs' GRC filing year and submitted as part of the DDOR.

gg. The Commission orders the creation of an open pathway for modifying various elements of the DIDF. The Commission orders the IOUs to propose any such modifications in the same Tier 2 ALs they file to request approval of distribution deferral projects.

This proceeding shall remain open to address issues related to Track 3, Sub-track 2 (Grid Modernization) and Track 1 long-term refinements.

1. Background

1.1. The Rulemaking and Related Applications

On August 14, 2014, the Commission opened Rulemaking (R.) 14-08-013 in order to establish policies, procedures, and rules to guide California Investor-owned Utilities (IOUs) in developing their Distribution Resource Plan (DRP) Proposals. We did so in accordance with the enactment of Assembly Bill (AB) 327,[1] an omnibus-style bill that impacted multiple aspects of the provision of regulated utility service and of the energy market, including Net Energy Metering (NEM), the Renewables Portfolio Standard, natural gas and electricity rates, and electricity resources. AB 327 added Pub. Util. Code § 769, which addressed both the IOUs' electric distribution planning protocols, as well as the Commission's obligation to review, modify, and approve the IOUs' DRP proposals:

> (a) For purposes of this section, distributed resources means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

[1] Stats. 2013, Ch. 611.

(b) Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources. Each proposal shall do all of the following:

(1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electrical grid or costs to ratepayers of the electrical corporation.

(2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.

(3) Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

(4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.

(5) Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

The IOUs met their July 1, 2015 filing deadline and their applications are identified as follows:

- Pacific Gas and Electric Company (PG&E): Application (A.) 15-07-006;
- Southern California Edison Company (SCE): A.15-07-002; and
- San Diego Gas & Electric Company (SDG&E): A.15-07-003.

1.2. The Scoping Memo and Ruling

Given the complexity and plethora of issues in this proceeding, the January 27, 2016 *Scoping Memo and Ruling (Scoping Memo and Ruling)*divided this proceeding into Three Tracks, with Track 3 focused on policy issues that the parties raised in comments on the applications and in the rulemaking proceeding. The *Scoping Memo and Ruling* also identified 22 issues for potential consideration as part of Track 3:

Table 1. Potential Track 3 Scoping Items included in the *Scoping Memo and Ruling*

Item No.	Item
1	Definition of distribution services that can be provided by distributed energy resources, to the extent these are not already addressed in Track 1 above related to the Locational Net Benefits Analysis (LNBA) methodology;
2	Competitive neutrality, grid neutrality, and third-party ownership of Distributed Energy Resources (DERs);
3	Grid modernization investment/deferral frameworks;
4	Control over dispatch of DERs;
5	The role of community choice aggregators (CCAs) and electric service providers and the utilities' responsibilities for competitive neutrality with respect to other wholesale electricity providers;
6	Utility role, business models, and financial interest with respect to DER deployment;
7	Coordination with other agencies with respect to climate policy;
8	Coordination with other procurement-related proceedings within the Commission, including the long-term procurement plan (LTPP) proceeding;
9	Coordination with the California Energy Commission's (CEC's) Integrated Energy Policy Report (IEPR) and demand forecast, as well as with the California Independent System Operator's

	Transmission Planning Process (TPP);
10	Maximizing ratepayer benefits of DERs, both in terms of overall system cost (including generation, transmission, and distribution) and greenhouse gas (GHG) reductions;
11	Value of DERs to customers;
12	Barriers to DER deployment that are safety or reliability-related. Other general discussion of barriers will be deferred to the IDER rulemaking;
13	DER deployment in disadvantaged communities;
14	Accounting for the GHG reduction benefits of DERs;
15	What grid modernization functions need to be deployed to support full DER integration;
16	Establishment of safety standards;
17	Data access and confidentiality issues, to the extent they are not resolved in Track 1 with respect to the LNBA and Interconnection Agreement methodologies;
18	Appropriate growth scenarios and/or forecasts for analysis of DER deployment;
19	Consideration of and need for optimized portfolios of DERs;
20	Whether and when to require periodic updates to utility distribution resource plans;
21	Relationship to utility general rate cases (GRCs); and
22	Integration of DRPs into utility distribution infrastructure planning and investment.

1.3. The Assigned Commissioner and Administrative Law Judge Rulings

On August 9, 2016, an *Assigned Commissioner's Ruling on Track 3 Issues* (*August 9, 2016 ACR*) was issued and invited party comments on the Commissioner's proposal to divide Track 3 into sub-tracks and streamline the number of items each sub-track would address:

1. Sub-track 1: DER Adoption and Distribution Load Forecasting (items 8, 9, and 18). In this track, the parties will consider the need to forecast DER adoption and loads at various levels of distribution system disaggregation; methodologies and data sources for distribution-level forecasting; and coordination with ongoing forecasting activities in the IEPR, LTPP, TPP, and any other applicable demand forecasts in determining the DER growth scenarios and/or anticipated investments in the distribution system to maintain reliability.

2. Sub-track 2: Grid Modernization Investments (items 3 and 15). In this track, the parties will consider what grid modernization functions need to be deployed to support full DER integration. As a result of this sub-track, the Commission may develop guidelines to govern utilities' future requests for funding related to grid modernization.

3. Sub-track 3: Integration of DRP into Planning and Cost Recovery Processes (items 20, 21, and 22). In this track, the parties will consider the processes for integrating DRPs into utility distribution planning and investment, including how the identification of deferral opportunities or other high value locations for DER deployment will lead to solicitations for DER services (or other market opportunities) and will inform utility investment requests in General Rate Cases.

On October 21, 2016, the Commissioner issued his *Assigned Commissioner's Ruling on Track 3 Issues* (*October 21, 2016 ACR*) which finalized the scope of Track 3. After reviewing the parties' comments, the Commissioner decided to maintain the three sub-tracks as proposed in the *August 9, 2016 ACR* but renamed sub-tracks 2 and 3 for greater clarity as follows:

Sub-track 2: Grid Modernization Investment Guidance; and

Sub-track 3: Distribution Investment Deferral Process.

On February 27, 2017, the Commissioner issued *his Assigned Commissioner's Ruling Setting Schedule for Submission of Distributed Energy Resource Growth*

Scenarios and Distribution Load Forecasting (*February 27, 2017 ACR*). The *February 27, 2017 ACR* acknowledged that on February 10, 2017, members of the Commission's DRP team facilitated a workshop entitled *DER Growth Scenarios and Distribution Load Forecasting, Distribution Resource Planning Track 3 Sub-track 1*, the objective of which was to consider the process and methodologies for forecasting the adoption of DER and distribution load in order to inform the DRP process. The workshop also considered the coordination issues and how the DRP will inform the Commission's Integrated Resource Planning (IRP) process, the CEC's IEPR demand forecast, and CAISO's TPP.

The *February 27, 2017 ACR* then adopted a work schedule wherein the working group was tasked with clarifying the use cases, proposing the methodology and assumptions for DER adoption scenarios, and developing approaches to disaggregate forecasts to the circuit level. While the assigned Commissioner expected that the growth scenarios will be developed consistent with the IEPR demand forecast used in the IRP and TPP, divergence from state-level assumptions may be necessary based on either better information available regarding the adoption of certain DER resources that has not been previously considered, or considerations regarding unique circumstances in application of the state level assumptions in local planning processes and models.

On May 16, 2017, the Commissioner issued his *Assigned Commissioner's Ruling Requesting Answers to Stakeholder Questions Set Forth in the Energy Division Staff White Paper on Grid Modernization (May 16, 2017 ACR)*. Energy Division prepared the *White Paper* to consider how the Commission should evaluate and authorize funding for proposed Grid Modernization investments.

On June 22, 2017, the assigned Administrative Law Judge (ALJ) issued his *Administrative Law Judge's Ruling Requiring Investor-Owned Utilities to File Assumptions and Framework Addendum, and for Parties to File Comments (June 22, 2017 Ruling)*. The *June 22, 2017 Ruling* sought comments in response to the Assumption and Framework document and the subsequent addendum for the adoption of the 2017 growth scenarios.

On June 30, 2017, the assigned ALJ issued his *Ruling Requesting Answers to Stakeholder Questions Set Forth in the Energy Division Staff Proposal on a Distribution Investment Deferral Framework*. The Energy Division Staff Proposal had been prepared with regard to the October 21, 2016 *Ruling on Track 3 Issues* to help build the record in support of an eventual establishment of an ongoing Distribution Investment Deferral Framework (DIDF) that will occur within the IOUs' annual distribution planning process. The DIDF builds upon the Competitive Solicitation Framework (CSF) and incentives Pilot developed in the Integration of Distributed Energy Resources (IDER) proceeding to establish an ongoing annual process to identify, review, and select opportunities for third party-owned DERs to defer or avoid traditional capital investments in the IOUs' distribution systems.

On August 9, 2017 the assigned Commissioner issued his *Assigned Commissioner's Ruling on the Adoption of Distributed Energy Resources Growth Scenarios* (*August 9, 2017 ACR*). The purpose of the *August 9, 2017 ACR* was to provide IOUs with direction on the application of their DER growth scenarios for their 2017-2018 planning cycle, and define the issues and process for establishing system-level and locational disaggregation methodologies for determination in the Track 3 decision. For the 2017-2018 cycle, the *August 9, 2017 ACR* directed the IOUs to use: (1) the adopted 2016 IEPR demand forecast update, with limited adjustments to photovoltaic (PV) and electric vehicle (EV) forecasts; and (2) their individual IOU-proposed methods to locationally disaggregate the data.

This decision addresses only Sub-tracks 1 and 3. Sub-track 2 (Grid Modernization) will be addressed in 2018.

2. Sub-track 1: Growth Scenarios

The *August 9, 2017 ACR* clarified that the most recent IEPR forecast, i.e. the system level forecast, is the most appropriate source for DER growth scenarios, but that updates may be necessary in the off-years between the full IEPR forecast due to material changes in policy or market adoption rates.

The *August 9, 2017 ACR* raised several issues to resolve in this decision. After staff discussions with CEC, we have determined that the forecasting update process will require further consideration of potential modifications to CEC's forecasting processes, as well as further Working Group discussions and formal input by parties, in order to acquire necessary data, align modeling processes, and to consider how to address uncertainty in the forecast at the circuit level. Development of DER growth scenarios is an iterative process that must be improved upon in future cycles. This year we establish the basis for system level forecasts, test a first iteration of these forecasts, and order additional procedural activity to address outstanding issues regarding the application of DER growth scenarios in future Distribution Resource Planning cycles.

In their comments on the Proposed Decision, ORA argued that this sub-track should be referred to as "Net Load Forecasting" and that the scope should be expanded to address the entire load forecast. We agree that the issues arising in the DRP extend beyond the DER growth forecasts to include the load forecast. However, the January 27, 2016 *Scoping Memo and Ruling* did not include the load forecasting within the scope of Track 3. We will maintain the scope of this decision to remain focused on DER growth scenarios, but will expand the scope of issues in 2018 to include load forecasting as it relates to distribution planning. Going forward, the Growth Scenarios Working Group will be referred to as the Distribution Load Forecasting Working Group.

2.1. Update of System-Level DER Forecasts in IEPR Off-years

In the Joint IOUs' Revised Assumptions and Framework document submitted on June 9, 2017, the IOUs each presented their proposed approach to developing a system-wide DER growth forecast for distribution planning. PG&E proposed to apply the 2016 IEPR forecast, while SCE and SDG&E proposed to apply their own DER forecasting methodology; SCE stated that that it was important to incorporate the latest adoption data and any recent policy changes into the forecast, in order to ensure that their distribution planning process reflects the most up-to-date assumptions.

The *August 9, 2017 ACR* determined that the most recent IEPR system-level forecast is the most appropriate source for DER growth scenarios. We affirm this direction. Using the adopted IEPR demand forecast ensures consistency across all planning processes between procurement and transmission and distribution planning, and minimizes redundancies in review processes by deferring to CEC for all DER forecasting. However, the DER growth forecasts in IEPR are currently updated on a biennial basis rather than annually. With rapidly changing market conditions for emerging DER technologies—EVs and storage in particular, and PV to a lesser extent—as well as the shorter planning horizon of Distribution Resource Planning, we agree that the IOUs need to incorporate more frequent updates to respond to changing policies and market conditions. This would necessitate annual updates to IEPR DER growth forecasts, and potentially entail shifting the schedule for adopting these forecasts to meet the IOUs' schedules for distribution planning.

Additionally, the IEPR demand forecast is adopted in January following a year of development and review, such that inputs provided in early 2017 are adopted in early 2018, but will not be applied to the IOUs' distribution planning processes until the end of 2018. CEC is currently evaluating the feasibility of updating its IEPR DER forecast on an annual basis, and whether it would be possible to accelerate the adoption of one or more of the DER forecasts so they can be applied with minimum lag time in distribution planning. In consultation with CEC, Commission staff have learned that annual updates for PV, EV, and energy storage forecasts will depend on the availability of both new data and CEC staff resources, which remain open questions at this time. Additional Achievable Energy Efficiency (AAEE) forecasts under existing CEC process, and this is expected to continue.[2] Small annual adjustments are made to the IEPR demand forecast will be adopted with fully updated DER forecasts in January 2018 because the full IEPR is underway; we direct the IOUs to use these forecasts for their 2018-19 distribution planning cycle.

It is our preference that the forecasts for PV, EV, and energy storage be updated annually by CEC on a schedule that will allow them to be applied within nine months of their adoption. However, the Commission will consider IOU-proposed adjustments to incorporate more recent changes in policy or

[2] The AAEE is based on the CPUC's Potential and Goals Study, which is done every two years. However CEC staff adjusts the AAEE forecast annually by updating the baseline year so that the updated AAEE numbers remain incremental to the baseline IEPR forecast. They also extrapolate the savings out an additional year. CEC staff also scale and extrapolate the aggregate level AAEE to produce hourly projections and load bus allocations.

market data that were not included in the most recently adopted forecast, but are reasonably expected to occur and, have a material impact, and can be modeled to quantify its impact on the forecast.

If an IOU-led approach is necessary, the IOUs are authorized to propose system-level adjustments via a Tier 2 Advice Letter to be filed no later than August 30 of a given year. In its review of any advice letter seeking adjustments to the forecast, the Energy Division should consult CEC staff.

Planning assumptions and calculations should be transparent; the sources of assumptions should be publicly available; and the utility should clearly explain the steps taken to adjust the IEPR numbers.

We recognize that further clarifying guidance may be necessary on how to apply certain DER forecast updates for distribution planning. The assigned Commissioner and assigned ALJ are authorized to take all procedural steps necessary to ensure that the objectives in this decision are implemented in an effective, fair, and efficient manner.

2.2. High and Low DER Growth Scenario Applications

In the *Scoping Memo and Ruling*, we stated that we plan to consider the impact of different DER growth scenarios on distribution planning outcomes, DER sourcing policies, and coordination with the IRP to determine optimal levels of DER deployment. The *August 9, 2017 ACR* only required the IOUs to apply the trajectory case growth scenario for 2017, but raised the question of how the scenarios applications are needed and how they should be applied for future planning cycles, which shall continue to consider. The DRP proceeding has identified two use cases for the high/low growth scenarios.

The Guidance for Section 769—Distribution Resource Planning, issued by the February 6, 2015 Assigned Commissioner Ruling (*February 6, 2015 ACR*) identified three scenarios for the IOUs to develop forecasts of projected DER growth over 10 years:

- Scenario 1: Adapts the IEPR "Trajectory" case for DER deployment for distribution planning at the feeder lever, down to each line section;
- Scenario 2: Adapts the IEPR "High Growth" case for DER adoption but also incorporates additional information from Load Serving Entities (LSEs), third party DER owners, and DER vendors; and
- Scenario 3: Based on very high potential growth in the use of DERs to meet transmission system needs, resource adequacy, distribution reliability, resiliency, and long-term GHG reductions.

The IOUs included these forecasted scenarios in their Distribution Resource Plans, filed on July 1, 2015. The 2017 Distributed Energy Resource Assumptions and Framework Document submitted by the IOUs on June 9, 2017, however, only presented a trajectory case scenario, and alternate scenarios have not been addressed.

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, ie., that which is reasonably expected to occur under existing ratepayer-funded tariffs and programs. This analysis is necessary for an accurate assessment of the transmission and distribution investments that autonomous DER growth is able to avoid. The Track 1 decision determined that assessing the benefits of autonomous growth requires an analysis of grid needs, and determination of needed investments to meet those grid needs, without autonomous DER growth included in the managed demand forecast[3]. The business-as-usual planning scenario, with autonomous DER growth included in the baseline forecast, would then determine ratepayer-funded DER integration costs stemming from such things as Grid Modernization investments and proactive hosting capacity upgrades.

In their comments, Clean Coalition and IREC argue that alternate scenarios, the high growth scenario in particular, should be incorporated into the distribution planning process in order to capture the full range of impacts of potential DER growth. The IOUs expressed concern that applying multiple DER growth scenarios to assess grid needs across their entire distribution system would require significant additional modeling and analysis that would divert resources from business-as-usual distribution planning activities. We agree that it is necessary to limit the scope of alternate DER growth scenario applications to what is needed for evaluating DER costs and benefits, determining optimal DER penetration levels and grid modernization needs, and establishing rates, tariffs, and/or other mechanisms to source DERs.

Thus, for the 2018-19 distribution planning cycle, the IOUs should focus on applying an alternate planning scenario that will enable them to assess the costs and benefits of DER grid integration and inform DER sourcing policies, as ordered in D.17-09-026. As discussed below, in future procedural activities, we will consider the implications of the IRP Reference Plan and what additional DER scenarios may be necessary in future distribution planning cycles as we

---

[3] The IEPR managed forecast is the baseline forecast adjusted by the AAEE and any other potential adjustments to DER forecasts that may be anticipated due to policy changes but have been adopted at this time.

further examine the relationship between DRP, IRP, and IDER to create a cohesive DER planning and procurement framework.

2.3. Locational DER Forecast Disaggregation

The *August 9, 2017 ACR* recognized that the appropriate method for disaggregating system-level forecasts to the circuit level is particular to the characteristics of each IOU's distribution infrastructure and modeling capabilities. At this time, we will not require a standardized methodology for locational disaggregation. However, in their comments on the IOUs' Assumptions and Framework document, NRDC and IREC raised questions about the IOUs' disaggregation methods, the level of uncertainty surrounding circuit level forecasts, and the impact of this uncertainty on determining grid needs. We agree that disaggregation methods need to be vetted through the Growth Scenario Working Group. The IOUs should seek consensus on best practices within the Working Group and incorporate them, as best as possible, in their disaggregation methods. The Commission will address any unresolved methodological issues in a future ruling or decision. NRDC also pointed out that a feedback and calibration process is needed in order to mitigate forecasting uncertainty. We agree that uncertainty increases as system-level forecasts are disaggregated to smaller geographic areas, and expect the IOUs to evaluate the effectiveness of past forecasts and to describe their approach to improve future disaggregation methodologies based on actual load and DER adoption data in the Distribution Forecasting Working Group.

Furthermore, it is critical to align with the CAISO on forecast assumptions at the busbar level. We order the IOUs to work with the CAISO to ensure consistency in DER forecast disaggregation methods; the CAISO and the IOUs should raise any issues that require resolution in the Distribution Forecasting Working Group.

2.4. Distribution Forecasting Working Group

The Working Group process in 2017 was largely limited to the review of the IOUs' proposed methodologies for system-level forecasts. Other Working Group parties, including IREC, NRDC, SEIA, Vote Solar, and Clean Coalition argued that the Growth Scenario Working Group should be continued on an ongoing basis to thoroughly review the various aspects of DER forecasting that will impact Distribution Resources Planning activities. While we find that IOUs' current application of the CEC forecast will be sufficient for the first iteration of the Distribution Resource Planning process, we agree that forecasting issues and methods should be further vetted and refined. In addition to the issues discussed in this decision, parties raised other factors that have a critical impact on ICA, LNBA, and GNA results that may need consideration to ensure that the most reliable forecasting methods and assumptions are applied. SEIA and Vote Solar, for instance, have specifically identified the importance of load shapes on how each DER impacts local distribution reliability.

We direct Energy Division to develop a process and schedule for resolving the issues discussed in this decision through the Distribution Forecasting Working Group. We order parties to file comments within two weeks of the issuance date of this decision recommending scoping issues for the next iteration of the Distribution Forecasting Working Group. Comments should be no longer than ten pages in length and should, at a minimum, suggest specific scoping questions for the two main unresolved issues discussed in this decision: DER forecast disaggregation methodologies, and using alternate scenarios for resource planning purposes. The Commission will then set the Working Group's scope and schedule in a subsequent ruling, and will rule on Working Group issues in a subsequent ruling. Commission Staff will be responsible for establishing the working group schedule, defining necessary outcomes deliverables for the Working Group, and ensuring that the meeting agendas will meet these outcomes. The IOUs shall contract with a facilitator to coordinate agenda setting, manage the Working Group meetings, and prepare a progress report to be submitted on June 15, 2018.

3. Sub-Track 3: Distribution Investment Deferral Framework

3.1. Background

The *October 21, 2016 ACR* included the establishment of a DIDF as the main focus of Sub-track 3. The *October 21, 2016 ACR* goes on to define the specific outcomes of Sub-track 3 as:

- Establishment of a process to identify opportunities for DERs to defer or avoid traditional distribution infrastructure projects;
- Establishment of a process for utilities to seek authorization and cost recovery for DER sourcing to enable deferral or avoidance of traditional investments; and
- Consideration of a process to ensure that the savings from deferred or avoided distribution investments are accurately reflected in concurrent or subsequent GRC filings.

The Commission hosted a Deferral Framework workshop on December 12, 2016 for Commission staff, IOUs, and stakeholders to discuss a number of issues related to these outcomes. Specifically, workshop discussions were scoped around the following objectives:

1. Establish a common understanding of how distribution infrastructure planning and cost recovery occurs today;

2. Explore how these existing processes can be modified to incorporate a framework for evaluating opportunities for DERs to defer or avoid traditional distribution system investments; and
3. Discuss relevant considerations for a future planning process and Deferral Framework that will inform a Deferral Framework Staff Proposal.

The Commission then issued a DIDF Staff Proposal[4] on June 30, 2017. The Staff Proposal drew from workshop presentations and discussions, and from experience gained in the IDER Incentives Pilot[5] to propose a number of items by which the IOUs and stakeholders may annually consider opportunities for third-party owned DERs to cost-effectively defer or avoid traditional investments in the IOUs' distribution systems. The Staff Proposal covered the following topics, which will form the basis of this Decision:

1. Learnings from the IDER Incentives Pilot;
2. Overview of the existing distribution planning and investment processes;
3. Proposed annual Distribution Resource Planning process to address Pub. Util. Code § 769;
4. Establishment of the Grid Needs Assessment (GNA), a proposed annual IOU deliverable that would report on the grid needs and planned projects that result from the annual planning process;
5. Initial deferral screening criteria to identify candidate distribution deferral opportunities from the annual planning process;
6. Prioritization metrics by which to characterize candidate deferral opportunities and identify projects with a high likelihood of resulting in successful, cost-effective investment deferrals;

---

[4] *Administrative Law Judge's Ruling Requesting Answers to Stakeholder Questions Set Forth in the Energy Division Staff Proposal on a Distribution Investment Deferral Framework* (Staff Proposal), June 30, 2017.

[5] Adopted in D.16-12-036.

7. Proposed Distribution Planning Advisory Group (DPAG), including composition, roles, process, deliverables, access to potentially confidential and/or market-sensitive information, contingency planning, and timelines;
8. Solicitation process, other DER sourcing mechanisms, and subsequent DIDF updates; and
9. Cost Recovery for DER projects that defer or avoid traditional IOU investments, and tracking IOU payments to DER projects.

The Staff Proposal solicited stakeholder input on 24 questions pertaining to numerous aspects of the proposed DIDF. Stakeholders submitted responses to those questions in comments on August 7, 2017, followed by reply comments submitted August 18, 2017.

3.2. Context of DIDF within Greater DRP Effort

The central objective of the DIDF is to identify and capture opportunities for DERs to cost-effectively defer or avoid traditional IOU investments that are planned to mitigate forecasted deficiencies of the distribution system. Such deficiencies are identified during the distribution planning process, wherein the IOUs evaluate the existing distribution system's ability to accommodate anticipated changes in system conditions, driven by forecasts of demand and DER adoption on a given substation or circuit. In other words, the DIDF evaluates opportunities to deploy cost-effective DERs that are incremental to the "autonomous growth" levels of DERs that are expected to be deployed as a result of Commission-administered tariffs and programs and/or customer preferences.

Through this lens, targeted distribution deferrals capture the incremental value of DERs above and beyond the value provided by business-as-usual DER deployment. This is to say that the DERs included in the managed forecast provide a certain amount of value to the IOUs' distribution and transmission systems. The Commission, in D.17-09-026, recognized this, and ordered the

IOUs to develop proposals by which the LNBA can quantify the locational value of such autonomous DER growth, such that the IDER proceeding can develop tariffs and programs that can capture this value.

We affirm that the DIDF is a crucial component of the DRP that works to meet the requirements of Pub. Util. Code §769 (b)(2), (b)(3), and (b)(4).[6] The DIDF represents California's first permanent marketplace for third party-owned DERs to provide services to the IOUs' distribution grids.

3.3. Annual DRP Process

Section 2 of the Staff Proposal describes an annual DRP process that builds upon the IOUs' existing distribution planning processes to achieve the objectives of Pub. Util. Code § 769. The new DRP process builds on the steps in the IOUs' existing distribution planning process and establishes an annual procedural schedule for the DIDF and Grid Modernization Investment Framework,[7] at issue in Track 3 Sub-track 2 of this proceeding. Figure 1 of the Staff Proposal provides an illustrative timeline of how the new DRP process overlays the existing planning process.

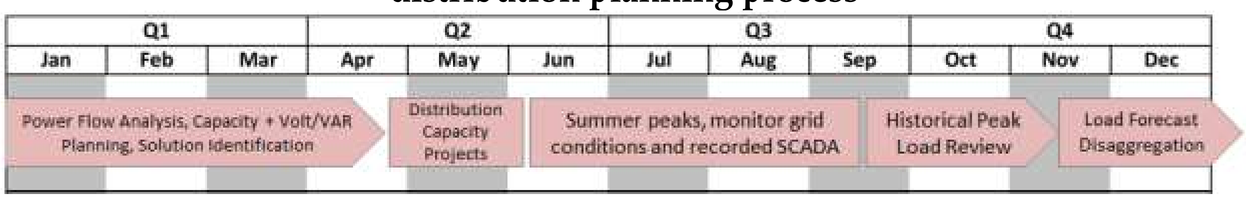
[6] (b)(2): Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives; (b)(3) Propose cost-effective methods of … …effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources; (b)(4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.

[7] we expect a subsequent Proposed Decision in this proceeding to establish the Grid Modernization Investment Framework.

The IOUs in comments[8] note that the timelines proposed in Figure 1 do not align with the IOUs' distribution capacity planning schedules, which are completed at different times based on each IOU's planning cycle.

We find that the process steps laid out in Figure 1 generally reflect the IOUs' descriptions in the December 12, 2016 workshop and in comments to the Staff Proposal. However, we agree with the IOUs that the illustrative timelines displayed in the Staff Proposal's Figure 1 do not accurately approximate the IOUs' annual planning timelines. The revised Figure 1 below provides a more accurate approximation, recognizing that the timing of each IOU's system peak determines when it commences with the "Historical Peak Review" step:

Figure 1. Process steps and approximate timelines of annual IOU distribution planning process



The Staff Proposal also provides the following high-level description of the process steps associated with the DIDF portion of the proposed annual DRP process:

1. Run power flow analyses and Integration Capacity Analysis (ICA) planning scenarios using current load and DER growth forecast assumptions;

---

8 *Joint Opening Comments of Pacific Gas and Electric Company (U 39 E), San Diego Gas & Electric Company (U 902 E), and Southern California Edison Company (U 338 E) on ALJ's Ruling Requesting Answers to Stakeholder Questions in Energy Division Staff Proposal on a Distribution Investment Deferral Framework* (IOU Comments), August 7, 2017, at 13.

2. Complete distribution planning process with assistance from power flow analyses and ICA scenarios, while compiling grid needs, planned projects, and candidate deferral projects for presentation in the GNA and LNBA;
3. Submit and publish GNA showing grid needs, planned investments, and candidate deferral projects in online maps and downloadable datasets; update and publish LNBA with candidate deferral projects;
4. Launch DPAG to evaluate candidate deferral opportunities and planning process results documented in the GNA and LNBA; and
5. DPAG recommends final distribution deferral projects; IOUs request Commission approval to launch solicitation for selected projects through formal filing.

Steps 1 through 3, in fact, pertain to both the Grid Modernization Investment Framework and to the DIDF. Step 1 entails implementation of two new DRP analyses—the ICA for distribution planning, and DER growth scenarios—that contribute to outcomes in both of these frameworks. These two analyses are described in the Staff White Paper on Grid Modernization[9] as follows:

- **Growth Scenarios**: In Track 3 [Sub-track 1] of the DRP Rulemaking, the IOUs are developing proposed forecasts of DER growth for application in their distribution planning assumptions. These forecasts are informed by the existing forecasting methodologies used for system planning and IRP.
- **Integration Capacity Analysis**: Track 1 of the DRP Rulemaking entails the creation of the ICA, which calculates the available load and generation hosting capacity at every circuit node in the IOUs' distribution systems based on the thermal, steady state voltage, voltage fluctuation, operational flexibility, and protection limits

[9] *Assigned Commissioner's Ruling Requesting Answers to Stakeholder Questions Set Forth in the Energy Division Staff White Paper on Grid Modernization*, May 15, 2017, at 19-20.

> of a given circuit. ICA results represent the incremental DER capacity a given circuit can accommodate before significant grid upgrades are needed.

Alongside the IEPR demand forecast, the ICA planning use case and DER growth scenarios serve as scenarios and assumptions that feed into both the existing distribution planning process and new DRP process. DER growth forecasts modify load and operational profiles at different system resolutions, which can be plugged into the ICA in order to determine the impact of expected DER adoption on a circuit's hosting capacity. This, in turn, can inform IOU determinations of location-specific Grid Modernization investments and proactive hosting capacity upgrades (which, in certain instances, may be deferrable by DERs).

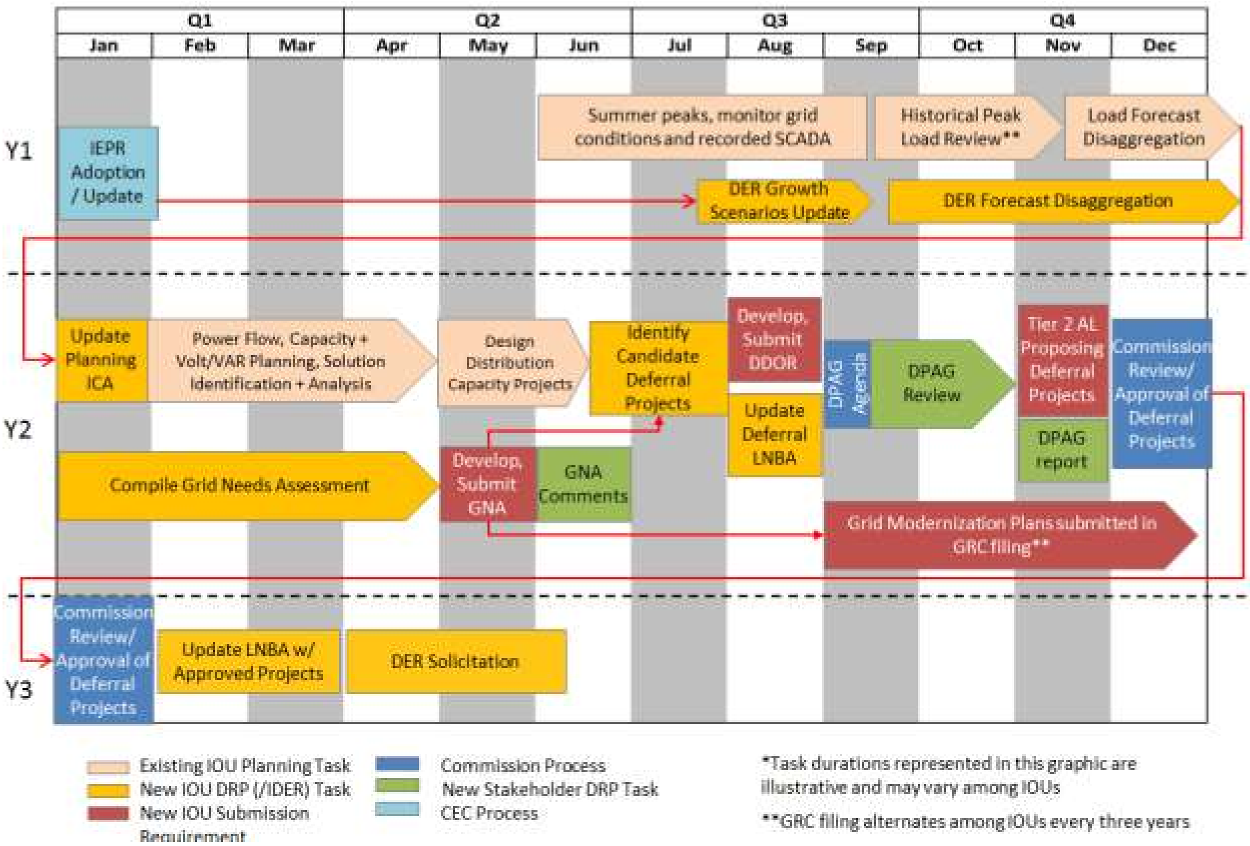
We direct the IOUs to implement DER growth scenarios and the ICA for purposes of the existing distribution planning and new DRP processes as described above and visualized in Figure 2 below. We clarify that the ICA, for the planning use case, is a tool that the IOUs should use alongside traditional planning tools and methods in completing the annual planning exercise. Similarly, DER growth scenarios are to be applied to load and operational profiles in traditional planning tools in the same manner as in the ICA. Specific methodologies for DER growth scenarios are discussed above, while those for the ICA planning use case are to be taken up in a Proposed Decision on Track 1 Long-Term Refinements expected in the first quarter of 2018.[10]

Steps 2 through 5 are discussed in the ensuing sections of this Decision. Figure 2 below reflects how the numerous elements of the new DRP process

[10] D.17-09-026, at 27-28.

adopted in this Decision overlay the steps of the existing annual distribution planning process, as described in Figure 1:

Figure 2. Existing distribution planning process and new Distribution Resource Planning cycle*



3.4. Grid Needs Assessment filing

Section 2.1 of the Staff Proposal describes an annual GNA submission that would serve as the main driver of the DRP process, wherein the IOUs would report on the grid needs and planned investments that result from the annual planning process to inform both the DIDF and the Grid Modernization Investment Framework. The GNA would also present a list of candidate distribution deferral opportunities that result from an initial deferral screening process. The Staff Proposal posits that the GNA should be due around April or

May of each year, concurrent with the completion of the annual planning process.

In lieu of Staff's proposed GNA, the IOUs in comments[11] propose a Distribution Deferral Opportunity Report (DDOR) that would contain details of each candidate deferral project that passes initial screening, the DER-related system need underlying those candidate projects, and the DER distribution service attributes required to meet the identified needs.

We reject the IOUs' proposal to replace a comprehensive GNA filing as described in the Staff Proposal with a DDOR filing that only reports candidate distribution deferral projects and the DER attributes required to meet those opportunities. In doing so, we affirm that a main purpose of the GNA is to provide transparency into the assumptions and results of the distribution planning process that yield the candidate deferral shortlist, proposed grid modernization investments, and proactive hosting capacity upgrades proposed to accommodate forecast autonomous DER growth. This will allow the Commission and stakeholders to ensure that the candidate deferral shortlist meets the objective of maximizing ratepayer benefits of DERs per Pub.Util. Code §769(b)(3). The IOUs' proposal to only report the grid needs and planned investments that underlie candidate deferral opportunities does not provide sufficient information by which such due diligence can occur.

The Staff Proposal notes the GNA would consist of a formal filing at the Commission with digital components, and requested party feedback on the type of procedural vehicle best suited for the annual GNA submission. We decline to

[11] IOU Comments, at 9.

adopt Office of Ratepayer Advocates (ORA)[12] and GPI's[13] proposal to require the GNA to be filed in an application, as applications are not conducive to timely and efficient review and approval processes demanded by an annual DIDF. Furthermore, requiring that the GNA is filed annually in an application would, on some level, replicate the level of evidence and review that go into the triennial GRC, and would introduce an element of subjecting IOU planning and investment decisions to a Commission decision. Such outcomes would violate many core tenets of how the Commission conducts cost-of-service ratemaking. Instead, we agree with IREC[14] that the GNA should be submitted in the simplest procedural vehicle that creates transparency and allows for formal stakeholder comment.

As indicated by the revised Figure 1 above, however, we recognize that the distribution planning process entails distinct steps between "Power Flow Analysis, Capacity + Volt/Var Planning, and Solution Identification," in which the IOUs identify forecasted grid deficiencies, and "Distribution Capacity Projects," in which the IOUs evaluate and engineer solutions to address identified grid deficiencies. We thus find value in establishing separate IOU reports documenting 1) forecast assumptions and grid needs, and 2) planned investments and candidate deferral opportunities, that coincide with completion of the planning process steps in which the IOUs develop such data.

---

12 *Comments of the Office of Ratepayer Advocates on Administrative Law Judge's Ruling Requesting Answers to Stakeholder Questions Set Forth in the Energy Division Staff Proposal on a Distribution Investment Deferral Framework* (ORA Comments), August 7, 2017, at 3-4.

13 *Comments of the Green Power Institute on the Staff Proposal on a Distribution Investment Deferral Framework* (GPI Comments), August 7, 2017, at 2-3.

14 *Opening Comments of the Interstate Renewable Energy Council, Inc. on Staff Proposal on a Distribution Investment Deferral Framework* (IREC Comments), August 7, 2017, at 5.

As such, the IOUs shall file, in reports pursuant to this Decision, a GNA by June 1 of each year, and a DDOR by September 1 of each year. This will allow the Commission and parties to gain familiarity with GNA results, and will provide DER providers an opportunity to begin customer engagement activities in areas with distribution needs, in advance of the DDOR filings. Parties may file comments within 30 days of GNA submissions in order to provide initial feedback on GNA data in advance of the Distribution Planning Advisory Group, and to make recommendations for how the GNA might be improved for future filings. These comments shall be filed in the R.14-08-013 proceeding or its successor DRP proceeding.

3.4.1. GNA and DDOR Contents

The GNA and DDOR shall provide a characterization of circuits according to the data types and attributes described below. GNA and DDOR data shall be made available in map form, as a pop-up layer atop the circuit models being developed for the ICA, and in downloadable, machine-readable datasets.

Datasets shall be organized by the circuits or geographic region containing each identified grid need, planned investment, and candidate deferral pertaining to one of the four distribution services adopted by D.16-12-036.[15] Each grid need, planned investment, and candidate deferral will occupy its own row in its respective database. There may be multiple items, and thus multiple rows, for an individual circuit or region, while circuits or regions without grid needs or planned investments should be identified as such.

---

[15] Distribution Capacity, Voltage Support, Reliability (Back-Tie), Resiliency (Microgrid).

3.4.1.1. Circuit-Level Planning Assumptions

The GNA shall include the following planning assumption data for each substation and circuit over a five-year forecast horizon. This data should be integrated into the GNA map layer, but provided in a separate dataset:

1. Demand and DER growth forecast
2. ICA planning values based on trajectory case demand and DER growth assumptions

3.4.1.2. GNA Contents

The GNA will present a report of the grid needs that result from the annual distribution planning process. Each grid need shall be characterized by the following attributes:

1. Substation, Circuit, and/or Facility ID: identify the location and system granularity of grid need
2. Distribution service required: capacity, reactive power, voltage, reliability, resiliency, etc.
3. Anticipated season or date by which distribution upgrade must be installed
4. Existing facility/equipment rating: MW, kVA, or other
5. Forecasted percentage deficiency above the existing facility/equipment rating over five years

3.4.1.3. DDOR Contents

Planned Investments

The DDOR will present a report of the IOUs' planned investments that provide one or more of the four distribution services adopted by D.16-12-036.

Each planned investment shall be characterized by the following attributes:

1. Project description
2. Substation

3. Circuit
4. Deficiency (MW/kVA, %)
5. Project type: Type of equipment to be installed
6. Project description: Additional identifying information
7. Distribution service required: capacity, reactive power, voltage, reliability, resiliency, etc.
8. In-Service Date
9. Deferrable by DERs, Y/N?
10. Estimated LNBA Range

Candidate Deferral Projects

The DDOR will also present the candidate deferral project shortlist that results from applying initial deferral screens to planned investments. Each candidate deferral project shall be characterized by the following attributes:

1. General geographic region of deferral opportunity, where appropriate, and/or specific location, (e.g., Substation, Circuit, and/or Facility ID)
2. In-Service Date
3. Distribution Service required
4. Expected performance and operational requirements (e.g., season needed, day(s) needed, range of expected exceedances/year, expected duration of exceedances)
5. Expected magnitude of service provision (MW/kVA)
6. Estimated LNBA range
7. Unit cost of traditional mitigation

We do not expect IOUs to publish distribution system planning data that violates the customer privacy provisions established in D.14-05-016, nor that creates a physical or cyber security risk to the electric system. The IOUs are to file a Tier 2 advice letter 60 days following the issuance date of this Decision proposing data redaction criteria. Such redaction criteria would also apply to ICA and LNBA data.

As mentioned in Section 3.4 above, the Staff Proposal refers to a GNA that, besides the four distribution services, reports on grid needs and planned investments related to Grid Modernization and proactive hosting capacity upgrades. This Decision establishes the format and contents of the GNA and DDOR for the purposes of the DIDF. However, we reiterate that the GNA is a primary deliverable underpinning a number of DRP frameworks. Ultimately, the GNA and DDOR may be modified by a forthcoming Track 2 Proposed Decision or other guidance to include reporting requirements pertaining to Grid Modernization investments and hosting capacity upgrades.

Establishing annual reports that contain data on distribution planning results presents a significant opportunity to inform the triennial General Rate Case. For instance, in an IOU's GRC filing year, the forecasts, grid needs, and planned projects presented in the GNA and DDOR could contribute to the baseline for that year's budget request. We expect that the information each IOU presents in its GRC testimony should be consistent with that which the IOU presents in its most recent GNA and DDOR reports, while affirming the IOU's ability to update any aspect of its GRC testimony due to emergent needs or changing forecasts that arise following that year's GNA and DDOR filings. The IOUs must explain any discrepancies between the GNA and DDOR reports and GRC testimony within the GRC testimony.

The information contained in the GNA and DDOR are snapshots in time that are meant to inform the selection of distribution deferral projects and grid modernization investments. In this vein, we affirm that the GNA and DDOR filed the year after a GRC filing year is inadmissible in the evidentiary record of that GRC proceeding, and may not be used to update the underpinning assumptions of GRC testimony that was filed the previous year. This would introduce a significant new variable into the complex GRC process, given that parties would be involved in evidentiary hearings on June 1 when the subsequent GNA is due, and then would be writing briefs on September 1 when the DDOR is due.[16]

3.4.2. GNA and DDOR Implementation

Finally, we turn to the matter of implementing the GNA and DDOR. The data compilation and reporting requirements we establish in this Decision, especially pertaining to the GNA, will entail a significant implementation effort on behalf of the IOUs in terms of modernizing the IOUs' planning tools, developing new information technology and analytics capabilities, and honing internal work flows by which the annual planning exercise is completed. To provide adequate time for the IOUs to meet the requirements of this Decision, we will gradually scale up the DIDF reporting requirements for each year going forward:

1. GNA due June 1. In 2018 IOUs shall provide data available, and provide full GNA in 2019;
2. DDOR due September 1.

We order the IOUs to propose work plans by which they will develop and implement the data compilation and reporting capabilities needed to complete the annual GNA and DDOR exercise, including a high-level description of the steps necessary to develop such internal capabilities and estimated interim milestones. Furthermore, the IOUs shall propose formats for the GNA and

[16] D.14-12-025, Table 4, at 42.

DDOR datasets based on the requirements laid out in Section 3.4.1 above. The IOUs may include in these proposals the most effective representations of the data attributes listed in Section 3.4.1. Both proposals should both be filed in a Tier 3 advice letter within 60 days of the issuance of this Decision. The Commission's Energy Division may at its discretion convene a workshop to review the IOUs' proposed formats in order to source stakeholder feedback on the user-friendliness and data presentation effectiveness, in advance of a Resolution on the matter.

3.4.3. DRP Data Access Portal

This decision's order pertaining to GNA and DDOR data sharing requirements presents an opportunity for synergies with the online map and downloadable dataset components of the ICA and LNBA ordered by D.17-09-026. As discussed in that decision,[17] the IOUs will create and publish network models of their entire primary distribution systems for ICA calculations, which will also host LNBA results.

Given that this Decision orders GNA and DDOR map data to be published on the same circuit model, it would be reasonable to make all DRP-related data accessible in the same online location. We thus order the IOUs to develop a central DRP data access portal, by which users can click between tabs to view ICA, LNBA, GNA, and DDOR data on the circuit map, and can query and export data in tabular form based on a geographic search or keyword search. Data portals shall also have Application Programming Interface (API) capability that

---

[17] At 52-53.

would allow users to access data in a functional format from back-end servers in bulk.

We recognize the significant implementation effort these data access portals will entail beyond developing the ICA circuit models. According to D.17-09-026, Ordering Paragraph 6, the IOUs are required to implement ICA circuit models for the interconnection and online map use case by July 6, 2018. D.17-09-026, Ordering Paragraph 16 further requires system-wide implementation of the LNBA for the DIDF use case by the date that the Track 3 decision requires submission of candidate distribution deferral projects. As noted above, the IOUs' inaugural DDOR submissions shall be due September 1, 2018.

We order the IOUs to propose a work plan for implementing the DRP data access portal within 90 days of the issuance of this Decision. The IOUs' proposed work plans shall be filed in a Tier 3 Advice Letter, include a high-level description of the steps necessary to develop the data access portal, and propose estimated interim milestones and a deadline for implementation based on those steps. The Commission's Energy Division may at its discretion host a workshop to discuss the format and function of the DRP data access portals. The Commission will then rule on the IOUs' proposed deadline in a resolution.

3.4.4. GNA, DDOR, and Data Access Portal Memorandum Account

We authorize the IOUs to establish a memorandum account to track the incremental costs of implementing the GNA, DDOR, and Data Access Portal to the specifications described in this decision. The IOUs shall create a sub-account within the memorandum account established in D.17-09-026 to track the incremental costs of ICA and LNBA implementation for this purpose. The IOUs shall file a Tier 1 advice letter within 30 days of the issuance date of this decision to propose establishment of this memorandum account.

3.5. Initial Deferral Screens

Section 2.2 of the Staff Proposal describes a process by which initial deferral screening criteria would be applied to the planned projects that result from the distribution planning process in order to arrive at a candidate deferral shortlist. The candidate shortlist would then provide the main focus of consideration in the Distribution Planning Advisory Group, whose main task would be to recommend deferral projects from the candidate shortlist that should go out for solicitation. Staff notes that the main goal of the DIDF should be to capture all potential deferral opportunities that carry a high likelihood of being cost-effective in order to maximize the ratepayer benefits of DERs per Pub. Util. Code § 769 (b)(3). To achieve this objective, Staff proposes four initial deferral screens based on presentations and discussion at the December 12, 2016 workshop:

Table 2. Staff-proposed initial deferral screens

Illustrative Screens	**Description**
Technical Screen	Determine whether DERs can meet the identified grid need • Based on the distribution grid services adopted in the IDER CSF • Services may evolve as more knowledge and experience is gained
Timing Screen	Determine whether a DER solution can be deployed in advance of the forecasted need date • Project type and complexity drive differing lead times

Illustrative Screens	Description
Economic/Financial Screen	Planned projects that carry a high likelihood of resulting in a cost-effective deferral • Consider adopting a minimum deferral value threshold to ensure administration of the Request for Offers is justified • In the future, this may also include a preliminary cost-effectiveness screen • ORA: Longer-duration deferrals, i.e., investments that can be deferred for a relatively longer period of time, should be prioritized over shorter-duration deferrals • The Utility Reform Network (TURN): Avoided projects should be prioritized over deferred projects; incremental services
Forecast Certainty	Grid needs/projects with a higher likelihood of materializing should be prioritized over those with a lower likelihood of materializing • Essentially a screen against high forecasting uncertainty • In general, grid needs that are nearer-term and/or driven by multiple customers are more certain than needs that are longer-term and/or driven by relatively few customers

The Staff Proposal also reviews IOU characterizations of the Technical and Timing Screens presented at the December 12, 2016 workshop, including types of distribution investments that can and cannot be deferred by DERs, as well as the relative deferability of distribution investments based on their forecast in-service date.

In comments,[18] Solar Energy Industries Association (SEIA)/Vote Solar recommend that initial deferral screens be limited to the Technical and Timing screens, as the Economic/Financial and Forecast Certainty screens are subjective and would allow the IOUs to be restrictive in their determination of candidate deferral opportunities. For instance, the Economic/Financial screen would require the IOUs to make assumptions about DER solutions and their costs, while the Forecast Certainty screen assumes that the IOUs have knowledge of which grid needs are likely to materialize. The IOUs similarly recommend[19] limiting initial deferral screens to the Technical and Timing screens, and note that the Economic/Financial and Forecast Certainty screens could be applied in the candidate project prioritization phase.

We are persuaded by SEIA/Vote Solar and the IOUs and adopt the Timing and Technical screens for use in the initial deferral screening process. We agree with IREC[20] that initial deferral screens should enable the IOUs to create over-inclusive, rather than overly restrictive, candidate deferral project shortlists, and agree with the IOUs that the Economic/Financial and Forecast Certainty screens should be considered as prioritization metrics. We also affirm that, per IREC,[21] Clean Coalition,[22] and IOU[23] comments that minimum project lead-times

---

[18] *Comments of the Solar Energy Industries Association and Vote Solar on 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* (SEIA/Vote Solar Comments), August 7, 2017, at 10-11.

[19] IOU Comments, at 16.

[20] IREC Comments, at 8.

[21] *Ibid.*, at 10.

[22] *Clean Coalition Comments on Stakeholder Questions Set Forth in the Energy Division Staff Proposal on a Distribution Investment Deferral Framework (Clean Coalition Comments),* August 7, 2017, at 6-7.

evaluated through the Timing screen are primarily driven by the time and process requirements of the IDER CSF RFO process, and not necessarily by the time needed to deploy modular DER solutions. We expect the Timing screen to evolve as the IDER proceeding develops non-RFO based DER sourcing mechanisms.

3.6. Prioritization Metrics

Section 2.3 of the Staff Proposal describes a process for characterizing projects on the candidate deferral project shortlist using prioritization metrics to assist the DPAG in making informed, high-confidence recommendations for DER solicitations that are likely to result in successful, cost-effective investment deferrals. For instance, it would be imprudent for the IOUs to go forward with a deferral project that would be expected to provide net ratepayer benefits, but is located in an area where potential DER host customers and/or opportunities for in-front-of-the-meter solutions are relatively low or non-existent. Prioritization metrics should screen out the deferral opportunities that have a low probability of success.

Staff reviewed the prioritization metrics presented by the Joint IOUs at the December 12, 2016 workshop, as well as the prioritization metrics employed by each individual IOU for the IDER Incentives Pilot. The Staff Paper proposed the five prioritization metrics SCE employed for its IDER Incentives Pilot, which are as listed in the following table.

---

[23] IOU Comments, at 17.

Table 3. Staff-proposed prioritization metrics

Metric	High Priority	Low Priority
DER attribute requirements	**Less** DER services required	**More** DER services required
Project timing certainty	**Nearer-term** needs; **less** historical **volatility** with load growth driving project need and required in-service date	**Longer-term** needs; **more** historical **volatility** with load growth driving project need and required in-service date
Financial assessment (capital project cost)	**Higher cost** of traditional capital project	**Lower cost** of traditional capital project
Market assessment (customer composition)	**Broad base** of large customers contributing to peak load (requires engaging relatively fewer customers to meet distribution need)	**Minimal number** of large customers contributing to peak load, or **highly residential** customer base (requires engaging many customers to meet distribution need)
Distribution topology (number of customers)	Projects that solve substation needs → provides a **larger** number of customers to potentially enroll in DER programs	Projects that solve specific circuit needs → provides a **smaller** number of customers to potentially enroll in DER programs

Parties, in comments, provided wide-ranging feedback regarding Staff's proposed prioritization metrics. Many parties argue that the Market Assessment metric, which would prioritize DER projects that serve fewer and/or non-residential customers over more and/or residential customers, is inappropriate and should be removed. California Energy Storage Alliance

(CESA) notes[24] that the Market Assessment metric would require DER providers to vie for a limited pool of potential DER host customers, which would limit the number of bids responding in an RFO and reduce the cost-effectiveness of the DIDF. Similarly, SEIA/Vote Solar[25] and Clean Coalition[26] note that larger numbers of residential customers would provide a robust and responsive marketplace for DER developers to target, while IREC[27] argues that prioritizing smaller numbers of large customers runs counter to the DRP goal of promoting customer choice of DER technologies.

Clean Coalition states[28] that SCE's Financial Assessment metric would prioritize distribution projects with high capital costs rather than high potential ratepayer value. Rather, they suggest, SDG&E's cost-per-MW should be used instead as a better indication of potential ratepayer value.

IREC[29] and Clean Coalition[30] argue against the DER attribute requirement metric, stating that prioritizing projects requiring less DER services is not technology-neutral and biases against certain types of DERs, and that deferral projects should move forward if DERs can cost-effectively meet the underlying grid need.

---

[24] *Comments of the California Energy Storage Alliance on Administrative Law Judge's Ruling Requesting Answers to Stakeholder Questions Set Forth in the Energy Division Staff Proposal on a Distribution Investment Deferral Framework* (CESA Comments), August 7, 2017, at 13.

[25] SEIA/Vote Solar Comments, at 15.

[26] Clean Coalition Comments, at 8-9.

[27] IREC Comments, at 11-12.

[28] Clean Coalition Comments, at 9.

[29] IREC Comments, at 11.

[30] Clean Coalition Comments, at 8-9.

In considering parties' arguments regarding prioritization metrics, we affirm that the main objective of prioritization metrics is to characterize candidate deferral projects in a way that enables the IOUs and the DPAG to identify which projects are most likely to result in successful, cost-effective deferrals that provide needed grid services. To meet these objectives, metrics are required to characterize whether: 1) a deferral project would likely result in net ratepayer benefits; 2) the forecast grid need underlying a potentially deferrable investment is likely to materialize; and 3) the potential DER marketplace within the electrical footprint provides an adequate market opportunity to host DER solutions. As such, we adopt Cost-Effectiveness, Forecast Certainty, and Market Assessment metrics to characterize and help prioritize projects on the candidate deferral shortlist.

To clarify, we do not adopt SCE's versions of these metrics listed above. Instead, we allow the IOUs to apply these metrics according to their own approaches, and decline to prescribe specific methodologies by which these metrics should be implemented in the initial roll-out of the DIDF. We do emphasize that the overarching goal of DIDF is that any deferral candidate project that can be cost effectively deferred through DERs should be deferred. We caution against an overly aggressive screening process that roots out viable deferral opportunities. We believe that the IOUs and the DPAG should gain experience with different prioritization approaches before prescribing a given methodology for ongoing use. For instance, the Cost-Effectiveness metric could be described in terms of SCE's total traditional project capital cost, SDG&E's cost-per-MW, or an approach that attempts to approximate the benefit-cost ratio of a DER solution. Forecast Certainty, on the other hand, could be approximated by many combinations of the IOUs' metrics employed in the IDER Incentives Pilot:

Table 4. IOU prioritization metrics from IDER Incentives Pilot related to Forecast Certainty

Utility	Metric	High Priority	Low Priority
PG&E	Number of customers causing need	Many	Few
	Project need (absolute and percent)	Large	Small
	Timing of need	Near-term	Long-term
SCE	Project timing certainty	**Nearer-term** needs; **less** historical **volatility** with load growth driving project need and required in-service date	**Longer-term** needs; **more** historical **volatility** with load growth driving project need and required in-service date
SDG&E	Weather factor adjustment	Average weather factors applied to the circuit or substation compared to overall system	Above-average weather factors applied to the substation or circuit compared to overall system
	Customer-specific development	Customer submittals for new or additional load	External reports of possible new developments

Utility	Metric	High Priority	Low Priority
	Customer growth	Multiple customer requests for new load, ground breaking ceremonies, and load materializing	No submittals for future load additions
	Historical Load	Forecast peak represents a relatively minimal increase or decrease from recent years' recorded peak	Forecast peak represents a relatively significant increase from recent years' recorded peak

With regards to the Market Assessment metric, the IOUs deployed the following approaches in the IDER Incentives Pilot in order to approximate the DER market opportunity associated with candidate deferral projects:

Table 5. IOU prioritization metrics from IDER Incentives Pilot related to DER Market Assessment

Utility	Metric	High Priority	Low Priority
PG&E	Number of customers causing need	Many	Few
	Ratio of projected need to customers/load on circuit/bank	Small	Large
	Timing of need	Long-term	Near-term

Utility	Metric	High Priority	Low Priority
SCE	Market assessment (customer composition)	**Broad base** of large customers contributing to peak load (requires engaging relative fewer customers to meet distribution need)	**Minimal number** of large customers contributing to peak load, or **highly residential** customer base (requires engaging many customers to meet distribution need)
	Distribution topology (number of customers)	Projects that solve substation needs → provides a **larger** number of customers to potentially enroll in DER programs	Projects that solve specific circuit needs → provides a **smaller** number of customers to potentially enroll in DER programs
SDG&E	Peak duration	Applicable peak is relatively constant over a given amount of time	Applicable peak is relatively spikey and/or concentrated to a limited time frame
	Customer profile mix	Relatively homogenous mix of customer classes on the circuit	Relatively diverse mix of customer classes on the circuit
	Peak timeframe	Peak allows for any DER technology to mitigate	Peak limits DER technology options to mitigate

Utility	Metric	High Priority	Low Priority
	Existing DER profiles	More diverse mix of existing DERs on the circuit	More homogenous mix of non-NEM DERs exists on the circuit
	Customer count	More	Less

A primary commonality amongst the three IOUs' market assessment metrics is the higher priority given to a larger and more diverse customer base. We thus agree with parties that SCE's Market Assessment metric does not properly gauge the diversity and robustness of a given area's DER market opportunity, and deny its use in the DIDF. We further agree with parties that the PG&E maximum customer threshold metric employed in the IDER Incentives Pilot is unreasonable to adopt at this time. Although the IOUs are correctly concerned about reliability in the advent of the DIDF, we agree with SEIA/Vote Solar[31] that the maximum customer penetration screen would bias against many urban circuits, which provide good opportunities for DER non-wires alternatives given the larger potential DER market and relative difficulty of building new distribution equipment, given CEQA, permitting, and construction issues.

3.7. Distribution Planning Advisory Group

Section 2.4 of the Staff Proposal describes a stakeholder-driven advisory body called the Distribution Planning Advisory Group (DPAG), whose primary objective would be to advise the Commission by recommending distribution deferral opportunities to go out for solicitation that have a high likelihood of resulting in successful, cost-effective deferrals. The DPAG would make such

[31] SEIA/Vote Solar Comments, at 14.

recommendations by first reviewing the candidate project shortlist presented in the GNA with regards to the assumptions, methods, and results of the planning process and the application of initial deferral screens, followed by application of prioritization metrics and further review. In its review of the GNA, the DPAG would also have the option of considering for deferral projects that did not make the candidate shortlist after the initial deferral screening process.

Staff in its proposal clarifies that the DPAG would not be a decision-making body, and would instead be charged with providing input into the final portfolio of distribution deferrals submitted for Commission approval. Staff also notes that, to the extent that the DPAG serves an advisory role to the Commission, and depending on the exact facilitation arrangement between Staff and the IPE technical consultant, establishment of the DPAG could elicit certain considerations related to: the Bagley-Keene Open Meeting Act; per diem or intervenor compensation for non-IOU DPAG participants; and Annual Reporting on Trusts and Entities Created by the Commission, per AB 1338 (2008) and Pub. Util. Code § 910.4.

3.7.1. Market Sensitivity and Confidentiality of Certain Types of Information

The Staff Proposal reviews the IOUs' concerns regarding the DPAG's access to potentially confidential, proprietary, or otherwise-market-sensitive information related to the annual planning process and selection of distribution deferral projects. The IOUs presented the following list of potentially market-sensitive information at the December 12, 2016 workshop:

- Actual costs of conventional distribution infrastructure projects under consideration for deferral;
- Location- and/or customer-specific confidential forecasts of load and resources;

- IOU proprietary projections and modeling outputs;
- Precise technical calculations in determining which conventional projects can be deferred and for how long;
- Technical and financial evaluation of DER technologies as alternatives to distribution investments;
- Comparative cost of solutions including the cost of conventional infrastructure;
- An assessment of DERs' effectiveness in providing distribution functions; and
- Discussions regarding where, when, and how to pursue alternative solutions.

3.7.1.1. Actual Costs of Conventional Distribution Infrastructure

The IOUs' concerns regarding market-sensitive information arises from the potential for engaged market entities to gain competitive advantages and/or manipulate a DER solicitation. This most directly relates to the first item in the above list, "Actual costs of conventional distribution infrastructure projects under consideration for deferral," and the potential for bidders to respond to a DER solicitation with bids marginally lower than the actual cost of the conventional project. D.16-12-036, which adopted the IDER Incentives Pilot, reflected this concern by excluding market participants from any DPAG discussions regarding market sensitive information established in D.06-06-066, especially the potential distribution costs that may be avoided by DERs. That decision also noted that future inclusion of market participants in distribution planning activities shall be determined in the DRP proceeding which is why are addressing this issue in this Decision.

In comments, the IOUs state[32] that the same confidentiality and market sensitivity issues identified in the IDER Incentive Pilot and DRP demonstration project proceedings should be mitigated and subject to the same data access protocols as recommended by the IOUs in those proceedings. The IOUs reiterate that the actual cost of traditional distribution projects should be treated as confidential to prevent market manipulation, a position shared by ORA.[33] The IOUs note that RFOs are reviewed by the IOUs' Procurement Review Groups (PRGs), which do not include market participants, as the PRGs may discuss confidential planning information relevant to the RFO, such as price forecasts. Similar to the current PRG process, the IOUs state that any current confidential planning information should not be shared with the DPAG if market participants are allowed to participate.

SEIA/Vote Solar counter[34] the IOUs' arguments in comments, asserting that distribution upgrade costs are not market sensitive and thus should not be treated as confidential. They argue that D.06-06-066, cited by D.16-12-036 to maintain the confidential status of distribution upgrade cost information in the IDER Incentives Pilot, pertains to bids in electricity procurement RFOs. Winning bid information from procurement solicitations such as Resource Adequacy and the Renewable Portfolio Standard, if accessed by market participants, would reveal to competitors the cost to produce an identical solution, and could lead to market collusion. This is different than avoided upgrade cost information, which serves as a price cap that defines whether bids are cost-effective and could win a

[32] IOU Comments, at 15, 19.

[33] ORA Comments, at 9-10.

[34] SEIA/Vote Solar Comments, at 17-20.

contract. A project's upgrade cost does not reveal to a DER provider what its competitors might bid.

Furthermore, SEIA/Vote Solar posits that revealing actual upgrade cost information would not, as anticipated by IOUs and ORA, lead DER developers to place bids just below the avoided cost. They describe that, in competitive markets where bids are not guaranteed to be accepted, bidders are motivated to bid at marginal cost, with the risk of losing the sale preventing "strategic" bids made above a firm's marginal cost. To illustrate this point, SEIA/Vote Solar reference the wholesale market price cap of $1,000-per-MWh, noting that, counter to the IOUs' logic, bids do not regularly come in right under the price cap.

In reply, the IOUs urge[35] the Commission to reject SEIA/Vote Solar's arguments. The IOUs state that SEIA/Vote Solar's admission that sharing DER deferral bid data post-solicitation could lead to market collusion implies that such a principle would apply to the "price to beat" for DER bidders. The IOUs further question why, if SEIA/Vote Solar argue that DER providers will always bid their marginal cost, why bidders need to know the actual cost estimates to form their bids, even when the IOUs are providing an indicative idea [through the LNBA].

We are persuaded by SEIA/Vote Solar's arguments and conclude that the 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

[35] *Joint Reply Comments of Pacific Gas and Electric Company (U 39 E), San Diego Gas & Electric Company (U 902 E), and Southern California Edison Company (U 338 E) on ALJ's Ruling Requesting Answers to Stakeholder Questions in Energy Division Staff Proposal on a Distribution Investment Deferral Framework* (IOU Reply Comments), August 18, 2017, at 8.

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.

D.06-06-066 disposes of issues related to Pub. Util. Code §454.5(g), implemented by AB 57 (2002, Wright), which requires the Commission to adopt appropriate procedures to ensure the confidentiality of market sensitive information related to post-Energy Crisis electricity procurement. D.06-06-066 defines "market sensitive" information as that which has the potential to materially affect an electricity buyer's market price for electricity, and clarifies that such information must, at the very least, be contained in procurement plans or power purchase agreements, or relate to these documents.[36] D.06-06-066 goes on to adopt, for most data types that meet this definition, a three-year window for keeping such data confidential.[37]

Such confidentiality provisions, as noted by SEIA/Vote Solar, were adopted to prevent market collusion amongst bidders who could structure bids to match their competitors' prices. The types of costs at issue here are not bids in a procurement, but the actual costs of distribution upgrade projects that serve as a price ceiling that bids must beat in order to be eligible for procurement. This cost information could be construed as meeting the D.06-06-066 definition of information related to the IOUs' distribution deferral procurement plans. However, it is unknown whether divulging the procurement cost cap would "materially affect an electricity buyer's market price for electricity." As TURN

[36] D.06-06-066, at 41.

[37] *Ibid*, at 43.

notes in reply,[38] it is too early to determine whether the number of firms that bid in a DER RFO will be sufficient enough to preclude market power concerns.

We agree in principle with SEIA/Vote Solar's argument, that DER solutions providers should be motivated to bid their actual marginal costs in competitive markets. That said, we also agree with TURN[39] that such a premise depends on whether the DER marketplace actually proves to be competitive.

Per IREC's suggestion,[40] the PRG can play a role in determining whether a sufficient number of DER providers are bidding at marginal cost in DER solicitations, thus resulting in a competitive marketplace. We direct non-market DPAG participants, including IOUs and Commission staff, to monitor DIDF procurement activity in the PRG. The IOUs can then make recommendations to modify this Decision's conclusion on actual system upgrade costs based on the market response to the IDER Incentives Pilot, DRP Demonstration Projects, SCE's Preferred Resource Pilot, and early iterations of the DIDF. The IOUs may recommend such modifications via the Advice Letter process established in Section 3.11 below.

We find this a reasonable approach to determining the impact of divulging the actual cost of distribution system upgrades. 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

---

[38] *Reply Comments of The Utility Reform Network Concerning the Staff Proposal on a Distribution Investment Deferral Framework* (TURN Reply Comments), August 18, 2017, at 3.

[39] *Ibid*.

[40] IREC Comments, at 13-14.

solicitation. Furthermore, until experience is gained, the risk of market manipulation in the DIDF entails far less potential ratepayer harm than collusion in, say, an RPS or Long Term Procurement Planning/IRP procurement. DER projects can only win a contract if they cost less than a traditional investment, so while the risk of market manipulation could result in suboptimal outcomes for ratepayers, ratepayers would never be subject to greater costs than business-as-usual IOU investments.

We balance the risk of market manipulation with the need to successfully achieve the multiple objectives of the DRP. The IOUs in reply express confusion as to why actual cost information would be preferred over indicative costs. First, within the context of the DIDF, actual cost information provides a clear and predictable market signal to DER providers, who can determine whether to bid in a DER solicitation if they are able to beat the avoided cost cap. The indeterminate error band around indicative costs does not provide precise enough information for DER providers to judge whether their bid would come in under the avoided cost. This could lead a number of DER providers to devote significant resources to developing bids, only for those bids to come in over the actual avoided cost. This would be a suboptimal outcome that would dissuade DER developers from developing bids in the first place, thus hampering the overall competitiveness and success of the DER marketplace established by the DIDF. To this end, we affirm that the IOUs may update the avoided cost value in their Tier 2 advice letter requesting approval to launch an RFO, described in Section 3.7.3 below, based on the most up-to-date cost assumptions. The IOUs shall explain the drivers of such a change in the advice letter.

Second, we agree with SEIA/Vote Solar[41] in comments that indicative values cannot be used for the LNBA use case, adopted by D.17-09-026, related to IDER cost-effectiveness and IRP. For this use case, the Commission required the IOUs to develop proposals by which the LNBA can report avoided Transmission and Distribution (T&D) costs and incurred integration costs associated with autonomous DER deployment for every distribution planning area (DPA) in the IOUs' service territories. Many details of this use case are still to be worked out within Track 1 of this proceeding, but SEIA/Vote Solar are correct that the LNBA would not be able to provide useful DPA-level T&D cost and benefit information to IDER and IRP if indicative costs are used instead of actual costs.

Finally, we agree with TURN,[42] who points out in reply that the IOUs do not deem actual distribution upgrade cost information confidential in GRC work papers. We add that distribution unit costs included in the IOUs' Rule 21 Unit Cost Guides adopted by D.16-06-052 are also not deemed market-sensitive and confidential. We find that it would be improper to apply different confidentiality provisions to the same type of information, regardless of the different contexts in which said information is provided.

3.7.1.2. Other Types of Potentially Market-Sensitive Information

Regarding the other potentially market sensitive data types identified by IOUs and listed in Section 3.7.1, it is not clear that any such data types will be explicitly discussed within the DPAG. We thus decline to rule on the market sensitivity or confidentiality of such data types at this time. That said, we agree

---

[41] SEIA/Vote Solar Comments, at 20-22.

[42] TURN Reply Comments, at 3.

with SEIA/Vote Solar[43] in reply that the onus is on the IOUs to make specific showings as to why certain data types should remain confidential due to statutes, regulations, decisions, or security concerns. They point out that the citations the IOUs include in comments and replies provide broad definitions of private and intellectual property, as well as R.15-06-009,[44] but none of these appear to directly apply to any of the types of distribution system data at issue in the DRP proceeding.

Absent specific examples, we affirm that the IOUs should adhere to existing rules and regulations pertaining to the types of data they share with the DPAG, including customer privacy provisions established by D.14-05-016. If the IOUs believe market participants should be excluded from discussions of certain data types they feel should remain confidential, the IOUs shall propose and provide the legal rationale for establishing non-market-sensitive and market-sensitive portions of the DPAG according to the agenda-setting process described in Section 3.7.3 of this decision.

3.7.2. DPAG Composition

Staff proposes that the DPAG consist of IOUs, Commission technical staff, stakeholders including ratepayer, environmental, community, and clean technology advocates, an IPE technical consultant, and market participants such

---

[43] *Reply Comments of the Solar Energy Industries Association and Vote Solar on 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* (SEIA/Vote Solar Reply Comments), August 18, 2017, at 3-6.

[44] Commission rulemaking, opened June 11, 2015, focused on the physical security of distribution infrastructure.

as DER project developers. In comments,[45] the IOUs reiterate their position expressed in the IDER CSF discussions that the DPAG should mirror the composition of PRGs and consist of IOUs, CPUC staff, an IPE, and non-market participants, but exclude DER market participants. The IOUs are concerned that developers could gain a competitive advantage and/or manipulate the market by participating in the DPAG and having access to data and assumptions related to the planning process that yields candidate distribution deferral opportunities. The IOUs state that, instead, the IPE can provide the DPAG with an industry perspective regarding DER technologies, their performance attributes, and their operating profiles. Many parties[46] instead support the inclusion of DER market participants, stating that DER developers' perspectives are needed to describe the capabilities of potential solutions that can be deployed to meet identified grid needs.

We agree with the Staff Proposal's recommendations and establish the DPAG to consist of IOUs, Commission technical staff, an IPE technical consultant, non-market participants, and DER market providers. We disagree with the IOUs that the DPAG necessarily reflects the role of PRGs, and decline to adopt their recommendation to exclude market participants due to concerns over competitive advantages. The DPAG is the central forum for IOUs and stakeholders to discuss the DER market opportunities that arise from the inputs and outputs of the annual planning process. Market participants' DPAG eligibility is thus critical for the DIDF to yield a successful DER marketplace.

---

45 IOU Comments, at 15, 19.

46 ORA Comments, at 8-9; GPI Comments, at 4; IREC Comments, at 13; SEIA/Vote Solar Comments, at 17; Clean Coalition Comments, at 10; TURN Reply Comments, at 2-3.

DPAG discussions regarding the GNA and DDOR will assist DER providers in evaluating market opportunities and engaging potential customers. DER providers in turn will inform the DPAG of the capabilities of their products, which in turn will help the IOUs hone their planning process related to the DIDF. Counter to the IOUs' assertion, the IPE should be primarily concerned with providing neutral expertise on distribution planning activities and the selection of candidate deferral opportunities—not on the technical attributes of DERs. DER technologies are diverse and rapidly evolving, and the annual forum on the distribution service marketplace is best informed by the providers who implement these technologies.

The PRG can play a role in determining whether DPAG-member DER providers actually gain a competitive advantage by either submitting a disproportionate number of bids, and/or winning a disproportionate number of contracts. Similar to monitoring the DER marketplace's competitiveness, we direct non-market participants, including the IOUs and Commission staff, to monitor DIDF procurement activity in the PRG. The IOUs can then make recommendations to modify this Decision's ruling on market participant inclusion in the DPAG, based on the market response to the IDER Incentives Pilot RFOs and the early iterations of the DIDF. The IOUs may recommend such modifications via the Advice Letter process established in Section 3.11 below.

3.7.3. DPAG Structure, Process, Recommendations, and Deliverables

Staff proposes that the DPAG serve as a Commission advisory body and be structured as a consensus-building process. The DPAG would recommend distribution deferral opportunities to go out for solicitation by first reviewing the candidate project shortlist presented in the GNA with regards to the assumptions, methods, and results of the planning process and the application of initial deferral screens, followed by application of prioritization metrics and further review. This process would be facilitated by the IPE in consultation with Staff to develop deferral project recommendations that are submitted by the IOUs requesting Commission approval in a Tier 3 Advice Letter to launch RFOs. Staff notes that, over time, the Commission may wish to require a Tier 2 advice letter filing instead in order to streamline the process. Furthermore, Staff proposes that the Tier 3 Advice Letter include preliminary contingency plans, the actual value of deferred or avoided investments, and a DPAG Report prepared by the IPE, which would incorporate stakeholder feedback in detailing the reasons for which certain candidate deferral projects did not achieve DPAG consensus. Staff notes that the Tier 3 advice letter vehicle likely allows for the most streamlined regulatory approval process.

In comments, ORA[47] recommends that the DPAG advises the IOUs and not the Commission, which would eliminate the need for the DPAG to comply with Bagley-Keene. Similarly, the IOUs[48] argue that the DPAG is intended to be analogous to the PRG and is not a "body" that makes collective recommendations and decisions on its own. Through this lens, the IOUs suggest that building consensus is not a realistic nor intended expectation of the DPAG, and that it would be infeasible to attempt to identify deferral projects that could achieve full DPAG consensus. Furthermore, the IOUs assert that neither the IOUs' Advice Letter nor the IPE DPAG Report should be responsible for compiling stakeholder feedback. Instead, both of these deliverables should

---

[47] ORA Comments, at 8-9.

[48] IOU Comments, at 20-21.

reflect their authors' views and proposals alone, while stakeholders would have formal avenues available, such as advice letter protests, in order to provide feedback on the IOUs' Advice Letters and the IPE's DPAG Report.

Regarding the approval vehicle, SEIA/Vote Solar[49] recommend establishing a Tier 2 Advice Letter rather than a Tier 3, which is similar to the process for RPS procurement. IREC adds[50] that shifting to a Tier 2 is one possible measure to help streamline the overall DPAG review and approval process.

A number of parties[51] also recommend that the IPE should not be responsible for facilitating the DPAG, such that he or she could focus on providing technical interpretations of GNA and DDOR results and the planning assumptions that yield them. These parties suggest that Commission staff or an independent third-party should retain facilitation duties.

We are persuaded by such arguments, and modify the Staff Proposal's recommendations regarding these items. First, we affirm that the DPAG is to advise the IOUs and not the Commission. Given this, the IOUs, instead of the IPE, shall be responsible for managing the DPAG, with Energy Division staff responsible for DPAG oversight. The Energy Division may, at its discretion, assume direct management of the DPAG or appoint a third-party facilitator.

However, in order to conduct the DPAG in a timely and efficient manner, the Commission shall retain authority over setting the DPAG's agenda. The IOUs, in their annual DDOR filing, shall include a proposed DPAG workplan

---

[49] SEIA/Vote Solar Comments, at 25.

[50] IREC Comments, at 15.

[51] GPI Comments, at 4; IREC Comments, at 14-15; SEIA/Vote Solar Comments, at 24; Clean Coalition Comments, at 11.

and agenda for the DPAG process. Parties may then provide comments on the proposed agenda within one week, followed by a letter from the Director of the Commission's Energy Division establishing the final agenda within two weeks. This advance agenda setting will avoid needless delays in the early parts of the DPAG process.

The IOUs' proposed DPAG agendas shall, at a minimum, encompass a review of: 1) planning assumptions and grid needs reported in the GNA; 2) planned investments and candidate deferral opportunities reported in the DDOR; and 3) candidate deferral prioritization. Importantly, as part of the discussion on candidate deferral opportunities, the IOUs shall present the underlying technical and operational requirements that a given DER alternative must provide in order to successfully meet the underlying grid need. Such technical requirements should be characterized within the DDOR under the "Expected performance requirements" attribute.[52] We expect that any resulting distribution deferral RFO would not include technical or operational requirements above and beyond those presented to the DPAG.

Finally, we order the IOUs to file a Tier 2 Advice Letter at the conclusion of the DPAG recommending the distribution deferral projects that should go immediately out for solicitation via the CSF RFO. This will help to streamline overall DIDF timelines while still providing an adequate opportunity for stakeholders to opine on the deferral projects recommended for approval. These advice letters shall include preliminary contingency plans, developed to the guidance provided below, as well as the IPE's DPAG Report, as attachments.

---

52 See Section 3.4.1.3.

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 separate resolution from that which disposes of consensus projects.

3.7.4. Contingency Planning

Staff proposes that the IOUs, in consultation with the DPAG, would be responsible for developing contingency plans for DPAG Recommended Projects for which DER alternatives do not materialize as anticipated. Contingency planning entails escalating degrees of design, cost estimation, procurement, and construction of traditional infrastructure solutions that can be implemented as the DER alternative progresses through stages of solicitation, construction, and operation. Staff includes a table describing how contingencies entailed by the Solicitation, Construction, and Operations phases of DER project development can be mitigated by traditional solutions. Staff then requests stakeholder feedback regarding whether the Commission should prescribe mitigations for specific contingencies, or whether such mitigations could 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.

We agree with the majority of party comments[53] that contingency planning should not be prescribed but rather determined by the IOUs on a case-by-case basis. The IOUs shall present proposed contingency plans for candidate deferral projects for review and feedback within the DPAG, which can help hone the

---

[53] ORA Comments, at 11-12; GPI Comments, at 5; IREC Comments, at 15-16 SEIA/Vote Solar Comments, at 25; CESA Comments, at 14.

contingency plans the IOUs file in their Tier 2 advice letter as described in Section 3.7.3 above. Per the IOUs' comments,[54] we find it valuable for the initial DPAG to propose developing contingency principles that can serve as guidelines for how IOUs evolve contingency planning over time. One of these principles should reflect what CESA and Clean Coalitions stress in comments: that DERs should be the first contingency option for the Construction and Operations phases. This would require notifying procurement runners up of their potential deployment. Contingencies can potentially be reduced by clearly describing the milestones and penalties related to a vendor not adequately achieving different stages of the process in DER service contracts.

3.7.5. DPAG Timelines

The Staff Proposal references its Figure 1 in proposing that the DPAG convene annually following the IOUs' submission of the GNA. Staff proposes two months for the DPAG to complete its review of the GNA and develop the portfolio of distribution deferral projects to go out for solicitation.

In Section 3.3 above, we revised Figure 1 to more accurately approximate the timelines associated with steps in the annual distribution planning process, in response to IOU comments alleging that the Staff Proposal's Figure 1 did not accurately capture such timelines. Furthermore, in Section 3.4, we bifurcated reporting of forecasts and grid needs from that of planned investments and candidate deferral opportunities in separate Grid Needs Assessment and Distribution Deferral Opportunity Report filings, due annually on June 1 and September 1, respectively.

---

[54] IOU Comments, at 22-23.

We order the IOUs to initiate DPAG meetings by September 15 of each year, two weeks following the IOUs' annual DDOR filing. The DPAG will then have six weeks to complete its review process. We reduce Staff's proposed DPAG timeline of two months by two weeks in order to reduce the overall timeline from DDOR to solicitation. The IOUs must then file their Tier 2 Advice Letters within one month following completion of the DPAG, by December 1 of each year.

3.8. Launching the Competitive Solicitation Framework RFO

Section 3 of the Staff Proposal indicates that the portfolio of Commission-approved distribution deferral projects will be procured via the IDER CSF. Staff notes that D.16-12-036 allocated four months for the RFO portion of the CSF process following Commission approval of pilot deferral projects in the IDER Incentives Pilot. For the ongoing Deferral Framework, Staff proposed that the CSF RFO launches no later than two months following Commission disposition of the DPAG's deferral project request.

Parties in comments provided minimal feedback on this proposal. ORA[55] and IREC[56] agree that launching CSF RFO two months after Commission disposition of the IOUs' Tier 2 Advice Letter appears to be reasonable. The IOUs,[57] on the other hand, recommend that the Commission decline to prescribe a schedule by which the CSF RFO should launch.

---

[55] ORA Comments, at 13.

[56] IREC Comments, at 16.

[57] IOU Comments, at 24.

We take a different direction and require the IOUs to launch the CSF RFO within 30 days of the Commission's disposition of the Tier 2 Advice Letter requesting approval of distribution deferral projects. We believe 30 days is entirely reasonable and feasible and ensures that the DIDF process can be a timely opportunity to defer traditional investments. Before issuing the RFO, the IOUs shall present their draft solicitation materials with the Commission's Energy Division staff.

3.9. Touchpoints with the IDER Proceeding

As discussed throughout this Decision, D.16-12-036 in the IDER proceeding adopted a number of elements pertaining to the CSF and IDER Incentives Pilot. That decision adopted certain issues such as the four distribution services that DERs can presently provide, and we adopt those same distribution services for the DIDF. The IDER Decision also referred for consideration in this proceeding the inclusion of market participants in the ongoing DPAG. Several issues will be examined through the IDER pilot process including potential continuation of an incentive mechanism and refinements to the CSF such as methodologies for incrementality, double-counting, and technology-neutral pro forma contracts. These issues are anticipated to be addressed in a 2018 Proposed Decision in the IDER proceeding. Any such future policy determinations shall apply to the DIDF.

3.10. Cost Recovery and Ratemaking

Section 4 of the Staff Proposal describes cost recovery and ratemaking principles for DER projects that are procured through the CSF (or future DER sourcing mechanism). Staff proposes that DER projects be pre-approved for cost recovery over the length of the contract, similar to cost recovery for Renewable Portfolio Standard projects. Staff further proposes that DER payments be tracked in the existing IDER Incentives Pilot balancing accounts, which can be repurposed for DER payments and IOU incentives for distribution deferral projects on an ongoing basis. Costs for DER payments would then be recovered through the applicable accounting mechanism that balances collection of the distribution revenue requirement.

Finally, Staff recommends that the actual value of deferred or avoided investments should be recorded and tracked over time as distribution deferral projects are authorized and as DER projects come online to provide contracted grid services.

In comments, the IOUs[58] recommend continuing the ratemaking treatment adopted in D.16-12-036, wherein the cost of any deferred or avoided distribution investments should not be subtracted from the adopted distribution revenue requirement before the subsequent GRC. Instead, the IOUs state that the value of any deferred or avoided investment would be reflected through a reduction in the next GRC's true-up of the base year revenue requirement, wherein the GRC revenue requirement is reset based on the previous GRC's approved budget versus the actual spending that ensued. The IOUs add that the aggregate nature of capital forecasts in GRCs, especially in attrition years where revenue requirements are multiplied by an escalation factor, makes it virtually impossible to determine the exact revenue requirement associated with a deferred or avoided investment. This in turn would render any reduction of adopted revenue requirements, or tracking deferred or avoided investments over time, particularly challenging.

---

[58] IOU Comments, at 25-26.

We agree with most of the IOUs' recommendations and characterizations regarding cost recovery and ratemaking issues. We agree to continue the ratemaking treatment adopted in D.16-12-036, wherein the IOUs shall track DER contract payments in the existing IDER Incentives Pilot balancing accounts—which shall be repurposed as Distribution Deferral balancing accounts—for recovery in the GRC, and DER incentive payments tracked in a balancing account for recovery in ERRA.[59] We further affirm that neither DER payments nor the avoided costs of traditional investments are reduced from the previously adopted revenue requirement. We believe that this ratemaking treatment will result in net ratepayer benefits over time, as deferring IOU capital investments will reduce the distribution capacity capital request in the GRC as described by the IOUs in comments. We clarify that this ratemaking treatment does not preclude the Commission's ability to reduce an IOU's revenue requirement request in an open GRC application in the instance where an IOU includes a specific project in its distribution capital request, while at the same time that project is being considered as a candidate deferral project.

However, we prohibit utilities from recovering costs for the same project more than once (double recovery). In the instance that the Commission approves a DER project to defer a specific investment that has been explicitly approved in the most recent GRC[60] and is included in the GRC revenue requirement, the utility may recover these costs through GRC revenues, and may not book

---

[59] D.16-12-036, Ordering Paragraphs 22 and 23, at 86-87.

[60] That is, in contrast to forecast distribution capacity budgets in a GRC that do not entail descriptions of specific planned distribution capacity investments.

payments for the corresponding DER project to the Distribution Deferral balancing account. Such cost recovery denial only applies through the DER contract period during which the IOU collects a revenue requirement for the approved traditional investment.

In comments to the PD, the IOUs state that this ruling is problematic, given that a DER project runs a significant risk of being more expensive than a traditional solution within the up-to-three-year period for which cost recovery for DER payments could be denied in the above scenario. The IOUs state that this could arise due to potential differences between the depreciation schedules of traditional solutions versus how DER payments could be structured within a contract. Also, the IOUs state that DER projects are likely to receive payments for ancillary services such as energy and capacity—costs that are not forecast in a GRC—beyond the distribution service that is primarily driving the deferral opportunity.

While distribution deferrals should only be approved if it is likely that a DER alternative can meet the underlying grid need at a cheaper cost over the life of the deferral, we agree with the IOUs in theory that a DER project could prove to be more expensive than a traditional project within a subset of the DER project's contracted term. On the other hand, a DER project could also be cheaper than the traditional project within the same time horizon. We affirm that, in the instance where the Commission approves the deferral of an explicitly-approved traditional investment in the most recent GRC, the IOUs should be made whole for any DER payments above what they are collecting in GRC revenues through distribution rates. We establish a process for determining this below. In the instance where DER projects receive payments for such ancillary services as energy and Resource Adequacy, the IOUs should book those costs to be recovered through the ERRA account, similar to other types of procurement costs.

In order to track the effectiveness of the DIDF in its pursuit of the objectives of Pub. Util. Code §769, we order the IOUs to file confidential reports to the Commission containing itemized data on payments made to contracted DER projects versus the estimated traditional spending such deferral projects were able to avoid. We recognize the challenges the IOUs describe in determining the actual revenue requirement impact associated with a given deferral project, and allow the IOUs to compute such estimates based on unit costs and typical depreciation schedules for given asset types. This report will be due concurrently with an IOU's DDOR submission in its GRC filing year. If the IOUs demonstrate to the Commission in their confidential DER payment reports that a DER project is more expensive than an explicitly-approved traditional project due to differences in depreciation schedules versus DER contract payments, the IOUs may file a Tier 2 advice letter requesting that the outstanding differential be added to the Distribution Deferral balancing account for recovery within that year's GRC application.

We also agree with TURN's recommendation in reply[61] that relevant performance metrics could help evaluate whether DER procurement is providing net benefits to ratepayers. We initially establish TURN's distribution capital per customer metric, which shall be calculated in each IOUs' GRC filing year and submitted as part of the DDOR. Additional performance metrics can be

[61] TURN Reply Comments, at 6.

discussed in the DPAG and proposed by IOUs via the process laid out in the following section.

3.11. Ongoing Modifications to DIDF

Section 3 of the Staff Proposal also recommends the establishment of a Tier 2 advice letter process for the IOUs to propose minor changes to various aspects of the DIDF. In doing so, staff notes that the nascence of regulatory constructs around procuring DER grid services necessitates that the DIDF is able to flexibly evolve in response to various developments, such as new sourcing mechanisms developed in the IDER proceeding. Modifications to such elements as initial deferral screening criteria, prioritization metrics, and DPAG timelines likely do not merit re-evaluation in a Commission rulemaking. The need for such changes could be identified in the IDER proceeding, in the ongoing DPAG, or on Staff's own motion, and would likely entail a Commission workshop to build further consensus around the proposed changes. In any case, such a process would ensure that the goals of Pub. Util. Code § 769 are continually met by enabling the DIDF to provide the oversight and advisory functions required by the latest developments in sourcing DERs to provide grid services.

We agree with Staff that an open pathway for modifying various elements of the DIDF is needed. When needed, we order such modifications to be proposed by the IOUs in the Tier 2 Advice Letters filed to request approval of distribution deferral projects. Such proposals could request modifications that achieve the following:

1. To expand the types of grid needs reported in GNA, as DER capabilities are proven, and/or policies are enacted that enable provision of certain DER capabilities, e.g., such that the types of non-deferrable investments in the IDER CSF WG report and Demo B reports could be realized down the road;

2. To change various structural parameters of the DIDF, including report deadlines, report contents, approval vehicles, or others in response to non-RFO sourcing mechanisms developed in IDER;
3. To specify methodologies for the initial deferral screens and prioritization metrics adopted herein, or to otherwise modify these screens and metrics;
4. To modify DPAG eligibility or market sensitivity determinations if, e.g., market participants' DPAG eligibility or access to actual cost information actually results in competitive advantages or market manipulations, as assessed in the PRG;
5. To modify other aspects of the GNA, DDOR, DPAG, or DIDF in a way that incorporates learnings from the IDER Incentives Pilot, DRP Demonstration Projects, or initial DIDF iterations as results of these programs and solicitations become known.

Categorization and Need for Hearing

This decision confirms that Track 3 of these consolidated proceedings is categorized as quasi-legislative. While the *Scoping Memo and Ruling* anticipated that there may be hearings, none were requested.

Comments on Proposed Decision

The proposed decision of the Commissioner Picker in this matter was mailed to the parties in accordance with Pub. Util. Code § 311. Opening comments were filed on January 8, 2018 by ORA, Interstate Renewable Energy Council, the IOUs jointly, California Energy Storage Alliance, California Independent System Operator Corporation, and Green Power Institute. Reply comments were filed on Janaury 16, 2018 by ORA, Interstate Renewable Energy Council, the IOUs jointly, California Efficiency + Demand Management Council, Natural Resource Defense Council, Clean Coalition, and The Utility Reform Network.

Non-substantive edits have been made throughout this Decision in response to some of the comments. The Decision also notes where comments have not been adopted.

Assignment of Proceeding

Michael Picker is the assigned Commissioner and Peter V. Allen and Robert M. Mason III are the co-assigned ALJs in this proceeding.

Findings of Fact

1. In the Joint IOUs' Revised Assumptions and Framework document submitted on June 9, 2017, the IOUs each presented their proposed approach to developing a system-wide DER growth forecast for distribution planning.
2. The *August 9, 2017 ACR* determined that that the most recent IEPR system level forecast is the most appropriate source for DER growth scenarios.
3. The IEPR demand forecast will be adopted with updated DER forecasts in January 2018.
4. With respect to high and low DER growth scenarios, the IOUs presented only an IEPR trajectory case scenario, and did not submit an IEPR high growth scenario, in their June 9, 2017 Distributed Energy Resource Assumptions and Framework Document.
5. The appropriate method for disaggregating system level forecasts to the circuit level is particular to the characteristics of each IOU's distribution infrastructure and modeling capabilities.
6. The *October 21, 2016 ACR* included the establishment of a Distribution Investment Deferral Framework as the main focus of Sub-track 3.
7. The *October 21, 2016 ACR* goes on to define the specific outcomes of Sub-track 3 as:
   - Establishment of a process to identify opportunities for DERs to defer or avoid traditional distribution infrastructure projects;

- Establishment of a process for utilities to seek authorization and cost recovery for DER sourcing to enable deferral or avoidance of traditional investments; and
- Consideration of a process to ensure that the savings from deferred or avoided distribution investments are accurately reflected in concurrent or subsequent GRC filings.

8. The Commission hosted a Deferral Framework workshop on December 12, 2016 for Commission staff, IOUs, and stakeholders to discuss a number of issues related to these outcomes.

9. The Commission then issued a DIDF Staff Proposal on June 30, 2017.

10. The Staff Proposal solicited stakeholder input on 24 questions pertaining to numerous aspects of the proposed DIDF. Stakeholders submitted responses to those questions in comments on August 7, 2017, followed by reply comments submitted August 18, 2017.

11. The central objective of the DIDF is to identify and capture opportunities for DERs to cost-effectively defer or avoid traditional IOU investments that are planned to mitigate forecasted deficiencies of the distribution system.

12. The DIDF evaluates opportunities to deploy cost-effective DERs that are incremental to the DERs that are expected to be deployed as a result of Commission-administered tariffs and programs and/or customer preferences.

13. Section 2 of the Staff Proposal describes an annual Distribution Resources Planning (DRP) process that would build upon the IOUs' existing distribution planning processes to achieve the objectives of Pub. Util. Code § 769.

14. Alongside the Integrated Energy Policy Report (IEPR) demand forecast, the ICA planning use case and DER growth scenarios serve as scenarios and assumptions that feed into both the existing distribution planning process and new DRP process.

15. Section 2.1 of the Staff Proposal describes an annual Grid Needs Assessment (GNA) submission that would serve as the main driver of the DRP process, wherein the IOUs would report on the grid needs and planned investments that result from the annual planning process to inform both the DIDF and the Grid Modernization Investment Framework.

16. Section 2.2 of the Staff Proposal describes a process by which initial deferral screening criteria would be applied to the planned projects that result from the distribution planning process in order to arrive at a candidate deferral shortlist.

17. Section 2.3 of the Staff Proposal describes a process for characterizing projects on the candidate deferral project shortlist using prioritization metrics to assist the DPAG in making informed, high-confidence recommendations for DER solicitations that are likely to result in successful, cost-effective investment deferrals.

18. Section 2.4 of the Staff Proposal describes a stakeholder-driven advisory body called the Distribution Planning Advisory Group (DPAG), whose primary objective would be to advise the Commission by recommending distribution deferral opportunities to go out for solicitation that have a high likelihood of resulting in successful, cost-effective deferrals.

19. Section 3 of the Staff Proposal indicates that the portfolio of Commission-approved distribution deferral projects will be procured via the IDER Competitive Solicitation Framework (CSF).

20. Section 4 of the Staff Proposal describes cost recovery and ratemaking principles for DER projects that are procured through the CSF (or future DER sourcing mechanism).

21. Section 3 of the Staff Proposal recommends the establishment of a Tier 2 advice letter process for the IOUs to propose minor changes to various aspects of the DIDF.

Conclusions of Law

1. It is reasonable not to require a standard methodology for disaggregation.
2. It is reasonable to affirm that the DIDF is a crucial component of the DRP that works to meet the requirements of Pub. Util. Code § 769(b)(2), (b)(3), and (b)(4).
3. It is reasonable to order the establishment of separate IOU reports documenting 1) forecast assumptions and grid needs and 2) planned investments and candidate deferral opportunities, that coincide with completion of the planning process steps in which the IOUs develop such data.
4. It is reasonable to require that initial deferral screens should enable the IOUs to create over-inclusive, rather than overly restrictive, candidate deferral project shortlists.
5. It is reasonable to affirm that the main objective of prioritization metrics is to characterize candidate deferral projects in a way that enables the IOUs and the DPAG to identify which projects are most likely to result in successful, cost-effective deferrals that provide needed grid services.
6. It is reasonable to conclude that the 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.

8. It is reasonable to conclude that distribution unit costs included in the IOUs' Rule 21 Unit Cost Guides adopted by D.16-06-052 are not market-sensitive and confidential.

9. It is reasonable to require that the IOUs should adhere to existing rules and regulations pertaining to the types of data they share with the DPAG, including customer privacy provisions established by D.14-05-016.

10. It is reasonable to affirm that the purpose of DPAG is to advise the IOUs and not the Commission.

11. It is reasonable require the IOUs to launch the CSF RFO within two months of the Commission's disposition of the Tier 2 Advice Letter requesting approval of distribution deferral projects.

12. It is reasonable to require that future policy determinations in the IDER proceeding shall apply to the DIDF.

13. It is reasonable to order the IOUs to track DER payments in the existing IDER Incentives Pilot balancing accounts, which shall be repurposed as Distribution Deferral balancing accounts, for recovery within the GRC.

14. It is reasonable to track the effectiveness of the DIDF in its pursuit of the objectives of Pub. Util. Code §769.

15. It is reasonable to conclude that an open pathway for modifying various elements of the DIDF is needed.

ORDER

IT IS ORDERED that:

1. With respect to Track 3, Sub-track 1: Growth Scenarios

   a. The Integrated Energy Policy Report (IEPR) demand forecast will be adopted with updated Distributed Energy Resources (DER) forecasts in January 2018. The Commission orders the Investor-Owned Utilities (IOUs) to use these forecasts for their 2018-19 distribution planning cycle.

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

   c. The IOUs shall vet disaggregation methods through the Growth Scenario Working Group and incorporate best practices in their planning processes.

   d. The Commission orders the IOUs to work with California Independent System Operator (CAISO) to ensure that there is agreement on DER forecast disaggregation.

   e. The Commission orders the IOUs to evaluate the effectiveness of past forecasts and calibrate their circuit-level DER forecasts based on actual data.

   f. The Commission directs Commission Staff to develop a process and schedule for resolving the issues discussed in this decision through the Growth Scenarios Working Group. We order parties to file comments within two weeks of the issuance date of this decision recommending scoping issues for the next iteration of the Growth Scenarios Working Group. Comments should be no longer than ten pages in length and should, at a minimum, suggest specific scoping questions for the two main unresolved issues discussed in this decision: DER forecast disaggregation methodologies, and using DER growth scenarios for policy planning purposes. The Commission will then set the Working Group's scope and schedule in a subsequent ruling, and expects to rule on Working Group issues in a subsequent ruling. Commission Staff will be responsible for establishing the working group schedule, defining necessary outcomes deliverables for the Working Group, and ensuring that the meeting agendas will meet these outcomes. The IOUs shall contract with a facilitator to coordinate agenda setting, manage the Working Group meetings, and prepare a progress report to be submitted on June 15, 2018.

2. With respect to Track 3, Sub-track 3: Distribution Investment Deferral Framework,

a. The Commission directs the Investor-Owned Utilities (IOUs) to implement Distributed Energy Resources (DER) growth scenarios and the Integration Capacity Analysis (ICA) for purposes of the existing distribution planning and new Distribution Resources Planning (DRP) processes as described in Section 3.3 of this decision and as visualized in Figure 2 in this decision.

b. The ICA, for the planning use case, is a tool that the IOUs must use alongside traditional planning tools and methods in completing the annual planning exercise.

c. The Commission orders the IOUs to apply DER growth scenarios to load and operational profiles in traditional planning tools in the same manner as in the ICA.

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

e. The GNA and DDOR shall provide a characterization of all circuits according to the data types and attributes described in Section 3.4.1. of this decision. GNA and DDOR data shall be made available in map form, as a pop-up layer atop the circuit models being developed for the ICA, and in downloadable, machine-readable datasets.

f. Parties may file comments within 30 days of GNA submissions in order to provide initial feedback on GNA data in advance of the Distribution Planning Advisory Group, and to make recommendations for how the GNA might be improved for future filings. These comments shall be filed in the DRP proceeding or its successor.

g. The IOUs shall file a Tier 2 advice letter 60 days following the issuance date of this Decision proposing DRP data redaction criteria that work to ensure the physical and cyber security of the electric system and reflect the customer privacy provisions established in D.14-05-016.

h. The information each IOU presents in its GRC testimony shall be consistent with that which the IOU presents in that year's GNA and DDOR reports, while affirming the IOU's ability to update any aspect of its GRC testimony due to emergent needs or changing forecasts that arise following that year's GNA and DDOR filings. The IOUs must explain any discrepancies between the GNA and DDOR reports and GRC testimony within the GRC testimony.

i. The Commission orders that the GNA and DDOR filed the year after a GRC filing year is inadmissible in the evidentiary record of that GRC proceeding, and may not be used to update the underpinning assumptions of GRC testimony that was filed the previous year.

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

    1. GNA due June 1. In 2018 IOUs shall provide data available, and provide full GNA in 2019;

    2. DDOR due September 1.

k. The Commission orders the IOUs to propose work plans by which they will develop and implement the data compilation and reporting capabilities needed to complete the annual GNA and DDOR exercise, including a high-level description of the steps necessary to develop such internal capabilities and estimated interim milestones. The Commission further orders the IOUs to propose formats for the GNA and DDOR datasets based on the requirements laid out in Section 3.4.1 of this

Decision. The IOUs may include in these proposals the most effective representations of the data attributes listed in Section 3.4.1. Both proposals shall be filed in a Tier 3 advice letter within 60 days of the issuance of this Decision. The Commission's Energy Division may at its discretion convene a workshop to review the IOUs' proposed formats in order to source stakeholder feedback on the user-friendliness and data presentation effectiveness, in advance of a Resolution on the matter.

l. The Commission orders the IOUs to develop a central DRP data access portal, by which users can click between tabs to view ICA, LNBA, GNA, and DDOR data on the circuit map, and can query and export data in tabular form based on a geographic search or keyword search. Data portals shall also have Application Programming Interface (API) capability that would allow users to access data in a functional format from back-end servers in bulk.

m. The Commission orders the IOUs to propose a work plan for implementing the DRP data access portal within 90 days of the issuance of this Decision. The IOUs' proposed work plans shall be filed in a Tier 3 Advice Letter, include a high-level description of the steps necessary to develop the data access portal, and propose estimated interim milestones and a deadline for implementation based on those steps. The Commission's Energy Division may at its discretion host a workshop to discuss the format and function of the DRP data access portals. The Commission will then rule on the IOUs' proposed deadline in a resolution.

n. The Commission authorizes the IOUs to establish a memorandum account to track the incremental costs of implementing the GNA, DDOR, and Data Access Portal to the specifications described in this decision. The IOUs shall create a sub-account within the memorandum account established in D.17-09-026 to track the incremental costs of ICA and LNBA implementation for this purpose. The IOUs shall file a Tier 1 advice letter within 30 days of the issuance date of this decision to propose establishment of this memorandum account.

o. The Commission adopts Timing and Technical screens for use in the initial deferral screening process.

p. The Commission adopts Cost-Effectiveness, Forecast Certainty, and Market Assessment metrics to characterize and help prioritize projects on the candidate deferral shortlist. We decline to prescribe specific methodologies by which these metrics should be implemented in the initial roll-out of the DIDF, and instead direct the IOUs to apply these metrics according to their own approaches. We do emphasize that the overarching goal of DIDF is that any candidate deferral project that can be cost-effectively deferred through DERs should be deferred.

q. 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. We affirm that the IOUs may update the avoided cost value in their Tier 2 advice letter requesting approval to launch an RFO, described in Section 3.7.3, based on the most up-to-date cost assumptions. The IOUs shall explain the drivers of such a change in the advice letter.

r. The Commission orders that the IOUs shall adhere to existing rules and regulations pertaining to the types of data they share with the DPAG, including customer privacy provisions established by D.14-05-016. If the IOUs believe market participants should be excluded from discussions of certain data types they feel should remain confidential, the IOUs shall propose and provide the legal rationale for establishing non-market-sensitive and market-sensitive portions of the DPAG according to the agenda-setting process described in Section 3.7.3. of this decision.

s. The Commission establishes the DPAG to consist of IOUs, Commission technical staff, an IPE technical consultant, non-market participants, and DER market providers.

t. The Commission orders that the IOUs, in their annual DDOR filing, shall include a proposed DPAG work plan and agenda for the DPAG process. Parties may then provide comments on the proposed agenda within one week, followed by a letter from the Director of the Commission's Energy Division establishing the final agenda within two weeks.

u. The IOUs' proposed DPAG agendas shall, at a minimum, encompass a review of: 1) planning assumptions and grid needs reported in the GNA; 2) planned investments and candidate deferral opportunities reported in the DDOR; and 3) candidate deferral prioritization. Importantly, as part of the discussion on candidate deferral opportunities, the IOUs shall present the underlying technical and operational requirements that a given DER alternative must provide in order to successfully meet the underlying grid need.

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

w. The Commission orders the IOUs to file a Tier 2 Advice Letter at the conclusion of the DPAG process, by December 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 separate resolution from that which disposes of consensus projects.

x. The Commission orders that contingency planning shall not be prescribed but rather determined by the IOUs on a case-by-case basis. The IOUs shall present proposed contingency plans for candidate deferral projects for review and feedback within the

DPAG, which can help hone the contingency plans the IOUs file in their Tier 2 advice letter as described in Section 3.7.3.

y. The Commission orders the IOUs to launch the CSF RFO within thirty days of the Commission's disposition of the Tier 2 Advice Letter requesting approval of distribution deferral projects. Before issuing the RFO, the IOUs shall present their draft solicitation materials with the Commission's Energy Division staff.

z. Future IDER policy determinations including potential continuation of an incentive mechanism and refinements to the CSF such as methodologies for incrementality, double counting, technology neutral pro forma contracts, and technical performance requirements shall apply to the DIDF.

aa. We agree to continue the ratemaking treatment adopted in D.16-12-036, wherein the IOUs shall track DER contract payments in the existing IDER Incentives Pilot balancing accounts—which shall be repurposed as Distribution Deferral balancing accounts—for recovery in the GRC, and DER incentive payments tracked in a balancing account for recovery in ERRA. We further affirm that neither DER payments nor the avoided costs of traditional investments shall be reduced from the previously adopted revenue requirement. We clarify that this ratemaking treatment does not preclude the Commission's ability to reduce an IOU's revenue requirement request in an open GRC application in the instance where an IOU includes a specific project in its distribution capital request, while at the same time that project is being considered as a candidate deferral project.

bb. We prohibit utilities from recovering costs for the same project more than once (double recovery). In the instance that the Commission approves a DER project to defer a specific investment that has been explicitly approved in the most recent GRC and is included in the GRC revenue requirement, the utility may recover these costs through GRC revenues, and may not book payments for the corresponding DER project to the Distribution Deferral balancing account. Such cost recovery denial only applies through the DER contract period during which the IOU collects a revenue requirement for the approved traditional investment.

cc. The IOUs shall book DER payments for ancillary services such as energy and Resource Adequacy to the ERRA account, similar to other types of procurement costs.

dd. The Commission orders the IOUs to file confidential reports to the Commission containing itemized data on payments made to contracted DER projects versus the estimated traditional spending such deferral projects were able to avoid. The IOUs may compute such estimates based on unit costs and typical depreciation schedules for given asset types. These reports will be due concurrently with an IOU's DDOR submission in its GRC filing years.

ee. If the IOUs demonstrate to the Commission in their confidential DER payment reports that a DER project is more expensive than an explicitly-approved traditional project due to differences in depreciation schedules versus DER contract payments, the IOUs may file a Tier 2 advice letter requesting that the outstanding differential be added to the Distribution Deferral balancing account for recovery within that year's GRC application.

ff. The Commission orders the establishment of a distribution capital per customer metric, which shall be calculated in each IOUs' GRC filing year and submitted as part of the DDOR.

gg. The Commission orders the creation of an open pathway for modifying various elements of the DIDF. The Commission orders the IOUs to propose any such modifications in the same Tier 2 ALs they file to request approval of distribution deferral projects.

3. Rulemaking 14-08-013 et al., and Application 15-07-005 et al., shall remain open.

4. This order is effective today.

Dated February 8, 2018, at San Francisco, California.

MICHAEL PICKER
President
CARLA J. PETERMAN
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
Commissioners