Distributed Energy Resources Deferral Tariff and Request for Offer Streamlining

California Public Utilities Commission Energy Division Staff Proposal

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Prepared by:

This Staff Proposal was authored by Naseem Golestani, Robert Peterson, Keishaa Austin, Gabriel Petlin, and Jonathan Frost

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Glossary of Terms

Acceptance Trigger: Staff proposes a 90% acceptance trigger for Clean Energy Customer Incentive offers. If an IOU procures 90% of the grid need during the subscription period, they will execute contracts. If 90% is procured, it is likely that the remaining grid need will also be procured.

Aggregator: An entity that coordinates the operation and dispatch of multiple DERs pursuant to a tariff or other contractual agreement.

Candidate Deferral Opportunity: A planned investment included on the shortlist of traditional projects to be deferred using DERs (i.e., "non-wires alternatives") after passing the two initial deferral screens: the technical and timing screens.

Clean Energy Customer Incentive (CECI): The CECI offers uniform simplified terms open to any customer type where customers are incentivized to enroll in the tariff and use their DERs to dispatch according to grid needs identified in the GNA/DDOR process. This tariff is run via aggregators who sign up customers.

Contingency Date: The date identified by the IOU for contingency plan implementation. It marks the point at which an IOU no longer pursues the deferral of a traditional planned investment by procuring DERs. Instead, the IOU moves forward with the traditional solution. Contingency plans and their implementation date are specific to a planned investment. Each contingency date and plan depend on grid need type and timing and the lead time needed to implement the traditional solution.

Contract: An agreement between two or more parties that is enforceable by law.

Cost Effectiveness Cap (Cost Cap): This cap is specific to each planned investment. For tariff purposes, it is calculated by the IOUs and published with subscription period launch. DERs that are procured individually or in aggregate for an amount equal to or less than the cost cap are considered cost effective. Staff proposes that the cost cap be used as the basis for tariff budgets.

Deferral Tariff: A contract between a utility and DER provider that defines the services, terms, and conditions under which DERs will be provided to the IOU. The CECI and SOC are types of deferral tariffs. Staff propose that the price and payment structure (i.e., compensation) be predetermined rather than bid competitively (see Tariff Budget definition).

Disadvantaged Communities: (DACs) These areas represent the 25% highest scoring census tracts in State of California's CalEnviroScreen 3.0 tool.

Distributed Energy Resources: Distribution-connected distributed generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

Distributed Energy Resources Management System: (DERMS) This is a software platform for communicating with and controlling DERs that use smart inverters. With DERMS, DERs can be dispatched to provide grid services. DERMS can work in concert with Advanced Distribution

Management Systems, which monitor DERs and grid conditions for automated grid management decision making.

Distribution Deferral Opportunity Report: (DDOR) This annual report submitted by each of the IOUs contains details about each planned investment identified to address grid needs presented in the GNA. The DDOR also presents a list of candidate deferral opportunities and the results of applying prioritization metrics to rank the potential for each opportunity to be deferred using DERs (i.e., "non-wires alternatives"). Other information, such as recommendation for DIDF reform, are included in the report. The report is often referred to with reference to the GNA as follows: "annual GNA/DDOR filing."

Distribution Investment Deferral Framework: (DIDF) a framework designed to identify opportunities where future distribution system upgrades can be deferred or avoided through distributed energy resource deployment as "non-wires alternatives".

Distribution Planning Advisory Group: (DPAG) a body formed by market participants and an independent professional engineer who advise the utilities on the selection of distribution deferral opportunities and provide input on the development of competitive solicitation for distributed energy resources.

Grid Needs Assessment: (GNA) This annual assessment and listing of grid needs identified by the IOUs informs the DIDF and Grid Modernization Investment Framework. The GNA reports is often referred to with reference to the DDOR as follows: "annual GNA/DDOR filing."

High Fire Threat District: (HFTD) Refers to the high fire threat areas in the CPUC's Fire Threat Map which was adopted by the CPUC in Decision (D.) 17-12-024. The map consists of three fire-threat areas (Zone 1, Tier 2 [high] and Tier 3 [extreme]) that have increasing levels of risk of wildfires associated with overhead utility power lines or overhead utility powerline facilities that also support communication facilities.

Incrementality: Refers to the rules established in D.16-12-036 regarding the incremental counting of DERs procured across programs to avoid double payment and double counting of DER services.

Integrated Capacity Analysis: (ICA) quantifies the available hosting capacity of every distribution circuit in the utilities' service territories to integrate distributed energy resources without triggering grid upgrades.

Initial Deferral Screen: The IOUs apply initial screening criteria to planned investments identified during their distribution planning processes to arrive at a shortlist of candidate deferral opportunities. Technical and timing screens were adopted for use in the DIDF.[1]

[1] See Ordering Paragraph 20 in D.18-02-004, Decision on Track 3 Policy Issues, Sub-Track 1 (Growth Scenarios) and Sub-Track 3 (Distribution Investment and Deferral Process), February 15, 2018, at 86.

Locational Net Benefits Analysis: (LNBA) a tool that can determine optimal locations for DER deployment based on cost-effective opportunities for DERs to defer or avoid traditional distribution system investments.

Offer Reservation: During the subscription period, DER providers submit offer reservations for a portion (or the entirety) of the grid need. The offer will be submitted at the price and terms published by the utility at the start of the CECI subscription period. The provider submits an affidavit to demonstrate they have a sufficient number of customers with DER siting plans or existing DERs to meet the grid need. The affidavit commits the DER provider to meeting a predefined list of milestones to ensure DERs are online in time for the grid need.

Phantom Projects: Refers to non-actionable projects that enter the IOUs' queue for deferral opportunities and prevent actionable projects from moving forward. Also referred to as "queue hogging."

Prescreening: Prescreening is a prequalification process required for DER providers to bid in DIDF Request for Offers (RFOs), make tariff offers, and be listed on IOU marketing materials for deferral tariffs. The prescreening application includes company details and organizational information, an initial screening of creditworthiness and financial information, confidentiality agreements, and other details. See "Appendix: Prescreening Application Content."

Planned Investment: A traditional ("wired") distribution investment identified by an IOU in the DDOR to address one or more grid needs presented in the GNA.

Prescreening Effective Period: Accepted prescreening applicants remain effective for two years. After two years an applicant can reapply.

Prescreening Fee: A fee collected from providers interested in being included in IOU marketing materials for deferral tariffs. The fee would cover IOU marketing costs. Staff propose that it be waived during the pilot period with costs tracked in a memorandum account.

Prescreening Period: The prescreening period opens on August 15th each year or the day the IOU files its GNA/DDOR and closes when the RFO bidding window closes. If no RFO is held, the prescreening period lasts 60 days.

Prioritization Metrics and Ranking (Tiers): The IOUs evaluate candidate deferral opportunities according to three prioritization metrics: cost effectiveness, forecast certainty, and market assessment. Opportunities the IOUs find have the greatest chance of being deferred for 10 years (or the anticipated contract period, which may be less) are ranked Tier 1. Opportunities with a lesser chance are ranked Tier 2 and those with the least chance are ranked Tier 3.

Procurement Margin: For the Clean Energy Customer Incentive, 120% of the grid need will be procured. The subscription period will remain open after the acceptance trigger until the full grid need plus a margin of 20% is procured to account for attrition.

Standard Offer Contract: Agreement between the utility and a provider, where the IOU compensates the provider for the delivery of DER services to defer planned investments. The terms and conditions are uniform and subject to limited modifications.

Status and Cost-Effectiveness Reports for CECI Pilots: Annual CECI pilot update reports included with IOU GNA/DDOR filings. The reports cover the status of each planned investment for which the IOU's launch CECIs and provide all cost-effectiveness assessment results available at the time of GNA/DDOR filing.

Subscription Period: The period during which CECI offers are accepted. Subscription period length is dependent on the planned investment. It extends from the date of subscription period launch until: (1) enough offers are accepted to meet the grid need (including a margin allowing for attrition); or (2) the date determined by the IOU for contingency plan implementation.

Tariff Budget: CECI budgets differ for each planned investment. The tariff budget is based on the cost cap specific to each investment.

Technical Screen: An initial deferral screen based on an IOU's determination about whether DERs can meet the identified grid need.[2] The following four grid needs were adopted for use in the DIDF: distribution capacity, voltage support, reliability (back-tie), and resiliency (microgrid).[3]

Timing Screen: An initial deferral screen based on an IOU's determination about whether a DER solution can be deployed in advance of the forecast need date with project type and complexity resulting in differing lead time estimates. To date, the IOU expectation for minimum lead time required to procure DERs in the DIDF using a Request for Offers process has been three years.

Unit Cost of Planned Investment: The cost to design and construct a planned investment.

[2] See D.18-02-004, Ordering Paragraph 42.
[3] See D.16- 12- 036, Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot, December 22, 2016, at 7 to 8.

Acronyms

API	Application Programming Interface
BIP	Base Interruptible Program
BTM	Behind the Meter
CAISO	California Independent System Operator
CalSSA	California Solar & Storage Association
CCA	Community Choice Aggregator/Aggregation
CECI	Clean Energy Customer Incentive
CESA	California Energy Storage Alliance
CPUC	California Public Utilities Commission
CSF	Competitive Solicitations Framework
DAC	Disadvantaged Community
DDOR	Distribution Deferral Opportunity Report
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management Systems
DIDF	Distribution Investment Deferral Framework
DPAG	Distribution Planning Advisory Group
DRP	Distributed Resources Plan
EDP	Emergency Dispatch Program
EE	Energy Efficiency
IFOM	In Front of Meter
GNA	Grid Needs Assessment
GRC	General Rate Case
ICA	Integration Capacity Analysis
IDER	Integrated Distributed Energy Resources
IEEE	Institute of Electrical and Electronics Engineers Standards Association
IOU	Investor Owned Utility
kW	Kilowatts
LBNA	Locational Benefits Analysis
MW	Megawatt
NEM	Net Energy Metering
OIR	Order Instituting Rulemaking

PG&E	Pacific Gas & Electric
RFO	Request for Offers
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SGIP	Self-Generation Incentive Program
SOC	Standard Offer Contract
TNPF	Technology-Neutral Pro Forma contract

Executive Summary

The purpose of this staff proposal is to present tariff sourcing frameworks and elements to increase the number of distributed energy resource (DER) deferral projects based on grid needs and associated planned investment identified in the Distribution Investment Deferral Framework (DIDF) process. The proposal also addresses issues with the current DIDF annual Request for Offers (RFO) process. The overall objectives of the proposal are to:

1. Streamline and scale up DER deferral procurement
2. Develop pilots to test the deferral tariff proposals and their elements
3. Clarify incrementality policy for DERs sourced for deferral

Staff proposes two DER tariff frameworks: (1) the Standard Offer Contract (SOC) and (2) the Clean Energy Customer Incentive (CECI). The SOC consists of a standard contract for DER procurement to decrease the transactional cost and risk compared to the current DIDF RFO process and is based on the existing Technology-Neutral Pro Forma (TNPF) contract. Given the relative complexity of the TNPF contract, this tariff is for larger scale providers of In Front of Meter (IFOM) DERs, but can be used by an aggregator of multiple customer-sited Behind the Meter (BTM) DERs.

In contrast, the simplified terms of the CECI are likely to facilitate a wider range of customer participation including the procurement of BTM DERs. This tariff will incentivize customers to enroll and use their DERs such that they can be dispatched by aggregators to address grid needs identified in the DIDF process. This tariff aligns existing programs with the DIDF process. Programs most likely to be leveraged include the Self-Generation Incentive Program (SGIP) and Net Energy Metering (NEM) when paired with storage. Customers that are not part of existing DER programs are also eligible to participate.

Staff proposes to pilot the SOC starting with an RFO launch on August 15, 2021. The IOUs would select one Tier 1[4] deferral opportunity to test the SOC in their 2021 Grid Needs Assessment (GNA)/Distribution Deferral Opportunity Report (DDOR) filings.

Staff proposes to pilot the CECI after project vetting in the 2021 Distribution Planning Advisory Group. In the 2021 GNA/DDOR filings, each IOU will propose three deferral opportunities to implement CECI Pilot 1 (the Deferral Opportunity Pilot). They will select one Tier 1 opportunity and two Tier 2 or Tier 3 opportunities. If no deferral opportunities are provided, the IOU will select three planned investments that pass the technical screen and have grid needs that occur within two

[4] Candidate deferral opportunities in the DIDF DDOR reports are ranked according to the timing, technical, and market assessment tests into Tier 1, 2, and 3 opportunities. Tier 1 opportunities are those that the IOUs determine to have the greatest chance of being deferred using DERs (i.e., "non-wires alternatives"). Refer to the "Glossary of Terms" for further details.

to five years.[5] After DPAG deliberation, and if approved, Staff expect the IOUs to launch CECI subscription periods in January 2022. We encourage the IOUs to exceed the minimum of one deferral project for the SOC pilot and three deferral projects for the CECI pilot.

All pilot projects will address grid needs identified through the annual GNA/DDOR filings. Within every GNA/DDOR filed during the pilot period, Staff proposes that the IOUs continue to identify at least three deferral opportunities to pilot the CECI (i.e., one Tier 1 and two Tier 2/Tier 3). All other Tier 1 opportunities should be proposed for DIDF RFO or the SOC. If the IOUs do not identify any deferral opportunities in the GNA/DDOR, the IOUs would be required to select at least three planned investments that pass the technical screen and have grid needs that occur within two to five years. The IOUs would report on the status and outcomes of each planned investment to which they apply the SOC or CECI in their annual GNA/DDOR filings. The SOC and CECI pilots may evolve from pilots into a program, and the IOUs could ultimately reduce or eliminate RFO use if outcomes are positive. See Table 1 below for SOC and CECI pilot timeframes and deferral project count estimates.

Staff proposes two additional CECI pilots for future consideration. They could be implemented in the 2022-2023 DIDF cycle after the IOUs gain experience with CECI use and more broadly roll out the DER management systems that may be needed to scale up the deferral of planned investments using DERs.[6] Under CECI pilots 2 and 3 (the Planning Area Pilots), <u>all</u> planned investments within a single distribution planning area chosen for pilot purposes would be automatically selected for CECI application if they pass the technical screen and address grid needs that occur within two to five years. CECI Pilot 3 differs from CECI Pilot 2 in that it includes an innovative approach to tariff funding wherein the combined cost caps for planned investments in the planning area will be pooled to form the tariff budget. The IOUs would select separate distribution planning areas for CECI pilots 2 and 3.

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[5] IOUs apply initial screening criteria to planned investments identified during their distribution planning processes to arrive at a shortlist of candidate deferral opportunities referred to as the DDOR. Technical and timing screens were adopted for use in the DIDF. Refer to the "Glossary of Terms" for further details.

[6] PG&E and SCE requested funding to procure DERMS and other DER software platforms in their recent General Rate Case filings.

Table 1. Standard Contract Offer and Clean Energy Customer Incentive Pilot Timeframes and Illustrative Deferral Project Count Estimates (Combined, All Three IOUs)

Date	SOC Pilot	CECI Pilot 1 "Deferral Opportunity Pilot"	
2021	• Pilot launch August 15th • 3 projects, 5 MW • $11.5 million • 10,000 customers		
2022	Repeat count	• Pilot launch January 15th • 9 projects, 15 MW • $25 million • 25,000 customers	
2023	Repeat count	Repeat count	
2024	Repeat count	Repeat count	
2025	Repeat count (pilot end)	Repeat count	
2026		Repeat count (pilot end)	
Pilot Totals After Five Years	**SOC Pilot**	**CECI Pilot 1**	**Total**
Projects	15 projects (minimum)	45 projects (minimum)	**60 projects**
Capacity	15 MW	75 MW	**90 MW**
Traditional project cost	$57.5 million	$125 million	**$182.5 million**
Customers	50,000 customers served by facilities with grid needs	125,000 customers served by facilities with grid needs	**175,000 customers**

Notes:

a. Capacity, customer, and traditional project cost counts were estimated based on 2020 Grid Needs Assessment/Distribution Deferral Opportunity Report planned investments that staff anticipate could be well suited to deferral tariffs.

b. This table reflects minimum project counts. Annually, Distribution Planning Advisory Group stakeholders seek to identify additional deferral projects.

c. The number of expected individual BTM residential and commercial customers enrolled in the pilots is not estimated here.

1. Introduction

1.1 Document Overview

Section 1 of the proposal provides a procedural background for the IDER and DRP proceedings, frames the need for deferral tariffs and RFO streamlining, the objectives and scope of the proposal, and guiding principles. Section 2 presents the Clean Energy Customer Incentive (CECI) and a description of its elements that are to be piloted as described in Section 3. Section 4 presents a framework for a standard offer contract and its elements to be piloted as well as proposals for streamlining the existing DIDF RFO process. Finally, Section 5 recommends that IOUs add an Emergency Dispatch for System Reliability Program as a near-term priority for an additional value stream to be added to the CECI.

1.2 Procedural Background

In the Integrated Distributed Energy Resources (IDER) Proceeding R.14-10-003, the CPUC developed and adopted a Competitive Solicitation Framework (CSF) for distributed energy resources (DERs) to provide guidance for the IOUs' competitive solicitations for DERs based on the grid needs identified in the Distribution Resources Plan (DRP) proceeding R.14-08-013. The CPUC initiated the DRP proceeding to implement Public Utilities Code (Pub. Util.) Section 769, which required IOUs to submit comprehensive distribution resources plans and create a framework for reducing barriers to DER deployment and targeting DER deployment to avoid or defer utility capital investments. The CPUC clarified the relationship between the DRP and IDER proceedings in D.15-09-022, explaining that the two proceedings would work together to create an end-to-end framework to implement Pub. Util. Section 769.

In December 2016, the CPUC issued D.16-12-036 which adopted a technology neutral CSF for DERs, a regulatory incentive pilot, a Distribution Planning Advisory Group (DPAG), and rules for incremental measurement of DER services (referred to as "incrementality"). The CPUC provided policy guidance for the CSF and required the utilities to develop a Technology-Neutral Pro Forma (TNPF) contract in 2019.[7] As part of the incentive pilot, the CPUC required each utility to select at

[7] In Ordering Paragraph 4 of D.16-12-036 on page 78, the CPUC specified the following 12 principles for the CSF:

- Framework meets the identified need on a least-cost, best-fit basis;
- Framework utilizes a competitive process with broad markets;
- Framework is technology-neutral;
- Framework is transparent as allowed within confidentiality boundaries;
- Framework identifies a need without prejudging the technology;
- Framework does not limit the amount of any one type of technology;
- Framework is a streamlined process;
- Framework is a fair and consistent process;
- Framework focuses on the identified need;

least one deferral pilot project and up to three additional projects to test a 4% pre-tax incentive on annual payments to DERs applied to IOU annual payments to DERs procured in lieu of traditional investments. The CPUC created the DPAG to engage stakeholders with reviewing candidate deferral opportunities. The DPAG advises and consults with the IOUs regarding the process for considering proposed distribution deferral pilot projects, contingency plans, and valuation components for the Incentive Pilot. The CPUC in D.16-12-036 also specified incrementality rules to count DER services provided and ensure no duplication with procurement in other proceedings, and ensure these services are incremental to existing efforts and avoid double-counting of services.[8]

In February 2018, the CPUC issued an Amended Scoping Ruling in R.14-10-003 to refocus the proceeding, in part, to "Consider how existing programs, incentives, and tariffs can be coordinated to maximize the locational benefits and minimize the costs of distributed energy resources."[9] In August 2018, the CPUC held a workshop to develop ideas for designing tariffs and alternative streamlined methods of solicitation for procuring DERs. In November 2018, the ALJ issued a Ruling directing parties to develop proposals for a distributed energy resources procurement tariff. In response to the November 2018 Ruling, parties submitted proposals for DER Tariffs in February 2019. In March 2019, Staff held a workshop in which the parties presented on their proposals for the DER Tariff. This staff proposal builds on party proposals and discussion in the March 2019 workshop.

IDER Pilot Deferrals

For the IDER pilot, SCE selected two substation upgrade projects and considered integrated hybrid resource types that would increase capacity for these two substations.[10] SCE completed its solicitation in May 2018. In November 2018, the CPUC approved four In Front of Meter (IFOM) energy storage contracts for distribution deferral and resource adequacy, totaling 9.5 MW that will defer the substation upgrades for 9.5 years. In June 2019, the CPUC approved two energy storage

- Framework provides sufficient assurance of performance;
- Framework allows for flexibility in the number and type of bids; and
- Framework includes a lessons-learned feedback loop

[8] Ordering Paragraph 3 of D.16-12-036 explains that the pilot project was to have the following counting method:

- Ensure that ratepayers are not paying twice for the same service;
- Ensure the reliability of a service, i.e., ensure it is not counting on a service to be there when the service might be deployed at another time or place;
- Not be unduly burdensome to participants;
- Be technology-neutral;
- Be fair and consistent;
- Recognize that a distributed energy resource is eligible to provide multiple incremental services and be compensated for each service; and
- Be flexible and transparent to bidders.

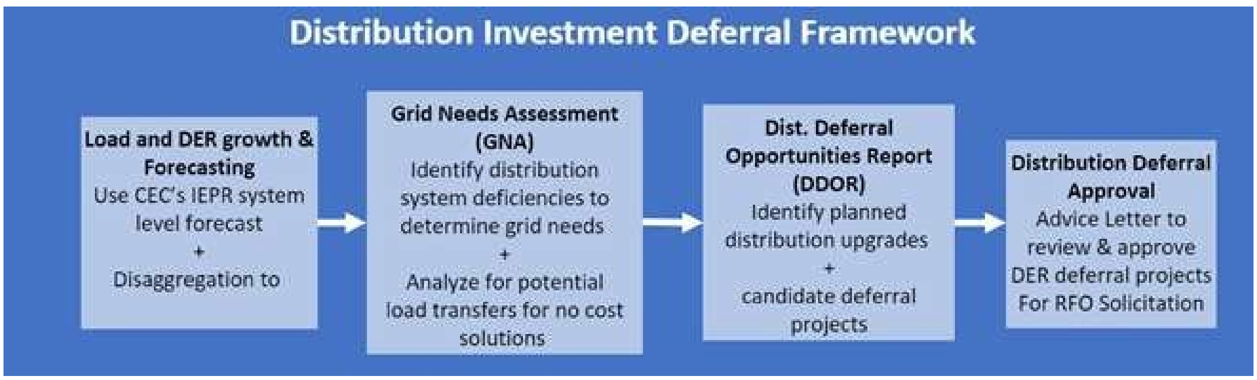
[9] R.14-10-003 Amended Scoping Ruling, February 12, 2019. Page 1.

[10] The SCE substation projects for the pilot were the Eisenhower Project in Cathedral City and the Newbury Project in Thousand Oaks.

contracts that PG&E awarded for its Gonzalez Substation in Monterey County totaling 2 MW and would last 5 years. SDG&E conducted solicitations in March 2018 for one project for its IDER pilot and did not receive any cost-effective bids.[11]

DRP Distribution Investment and Deferral Framework

The Distribution Investment and Deferral Framework (DIDF) was developed in the DRP Proceeding (R.14-08-013) to build off of the CSF from the IDER Proceeding R.14-10-003 and establish an ongoing annual process to identify, review, and select opportunities for competitively sourced DERs to defer or avoid IOU traditional distribution capital investments. The DIDF is designed to increase transparency in the IOUs' annual distribution planning process, select deferrable projects, and seek non-wires alternatives through competitive solicitations.



The CPUC in D.18-02-004 directed the IOUs to annually submit a Grid Needs Assessment (GNA) wherein the IOUs report on the grid needs and planned investments to inform both the DIDF and the Grid Modernization Investment Framework. D.18-02-004 also requires the IOUs to annually file a Distribution Deferral Opportunity Report (DDOR), with details of each candidate deferral project that passes initial screening, and the DER distribution service attributes required to meet the identified needs.

The DPAG vets DDOR reports to identify candidate projects that should be issued for competitive solicitation. D.18-02-004 furthermore required the IOUs to develop a central DRP data portal through which market entities view the GNA, DDOR, Integrated Capacity Analysis (ICA), and Locational Benefits Analysis (LBNA) data available as tabs that users can click between on a circuit map. Users can query and export data and access the data through an Application Programming Interface (API).

Subsequent to D.18-02-004, the CPUC issued a Ruling in November 2018 in R.14-08-013 clarifying how the CSF adopted in the IDER Proceeding R.14-10-003 would apply to the 2019 DIDF solicitations and clarified the process and schedule to approve the 2019 DIDF competitive

[11] SDG&E selected circuits 303 and 783 in Carlsbad for its IDER pilot.

solicitations. The Ruling furthermore allowed the IOUs to propose to diverge from the CSF or apply requirements that had not been resolved if the IOUs provided a detailed explanation of the solicitation requirements and justification as to why any divergences would be needed.

The IOUs held DIDF RFOs reflecting the 2018, and 2019 GNA/DDORs. During the 2018-2019 DIDF RFO cycle, SGD&E and SCE did not select any bids and as a result no projects went to contract. PGE, on the other hand, sought CPUC approval of 3 contracts during the 2018-2019 DIDF RFO cycle. The results of the 2019-2020 DIDF RFO are still pending. PG&E had three Candidate Deferral opportunities result in contracts for 15.35 MW of IFOM energy storage. To date, SDG&E has not had any deferrals.

1.3 Why DER Tariffs are Needed

The purpose of this staff proposal is to present DER tariff sourcing frameworks and elements to address issues that prevent the successful procurement of a greater number of DER deferral opportunities as well as lay out the pilots to test these concepts.

Why DER Tariffs Are Needed to Advance Distribution Planning Objectives to Integrate DERs

Several challenges exist with the current DIDF RFO process, which appear to limit its success in procuring DERs as non-wires alternatives. Some of the main challenges in the DIDF RFO process include:

Changing distribution system needs

- **Issue:** Developers submit bids based on RFO terms, and then, they sometimes see the terms change as the IOUs update the distribution needs. This creates uncertainty and costs for bidders. The IOUs can cancel the RFOs and bidders have no recourse for the lost investment in bidding. In subsequent IOU forecasts the same needs can materialize again, but with less time for deferral and pressure to build the wires solution to meet the needs.
- **Solutions:** Staff believes the Clean Energy Customer Incentive (CECI) is more flexible to respond to changing grid needs because it incorporates the "ratable" concept of procuring different increments of DERs over time to meet the needs instead of procuring for the full needs all at once.[12]

Over/under procurement risk

- **Issue:** RFO contracts are generally for specific capacity of DER to meet a grid need. If the grid need goes down, the IOUs risk procuring more DERs than needed. If the grid need

[12] Ratable procurement is discussed further in Section 2.2

goes up, there is either insufficient time and/or inflexible IOU terms to procure additional DERs. If the grid need goes away, the IOUs risk being locked into a DER contract that may no longer be needed.

- **Solutions**: The proposed CECI is more flexible at mitigating these risks. Instead of procuring all the DERs at once, the IOUs would procure the DERs in "ratable" increments and the payment structure balances the risk more equitably. For example, the CECI would pay a Behind the Meter (BTM) provider a small deployment payment to connect to the grid, and then pay only for performance of grid services. These terms reduce (but do not eliminate) over-procurement and mitigate under-procurement risk, as the IOU can add additional capacity through the aggregators.

Near-term deferrals not feasible

- **Issue**: Generally, the IOUs must procure DERs at least one year in advance of the planned investment's in-service date. For planned investments less than three years away, RFO-based solicitations are currently not feasible, because the RFO process takes too long to procure and operationalize DERs.
- **Solutions**: SOCs and CECIs can accelerate the procurement timeline and increase the feasibility of meeting near-term deferrals.

Forecast Uncertainty

- **Issue**: IOU DIDF RFOs currently target planned investments for deferral that are 3-5 years away. The IOUs consider needs greater than 5 years out as too uncertain to justify procurement of DERs that may be unnecessary should the need not materialize.
- **Solutions**: As described in the over-procurement discussion above, BTM DERs are a lower risk procurement method for longer-term deferral needs. The BTM CECI proposal matches well with longer term needs to allow time for customer enrollment and to help mitigate the over procurement issue. BTM CECI can be lower cost "no regrets" procurements, because (1) ratepayers risk only paying the deployment payment if the deferral is not needed, (2) the fleet of deployed DERs may later be called upon to provide deferral services as new needs arise.

Interconnection queues and delays

- **Issue**: IFOM DERs face interconnection queues and delays that can prevent the DERs from meeting the deferral contingency deadline.
- **Solutions**: BTM DERs can achieve interconnection in a matter of days-to-months. Alternative sourcing mechanisms proposals like the CECI and SOC in this paper would shorten the procurement timeline of IFOM DERs.

BTM DERs have, thus far, not been selected in DIDF RFOs

- **<u>Issue</u>**: DIDF RFOs are technology neutral and open to IFOM and BTM DERs, but thus far, IFOM energy storage is the only DER to be awarded deferral contracts. BTM DER bids have not been selected for a variety of reasons including: cost-effectiveness, scope of deferral need, and incrementality issues.
- **<u>Solutions</u>**: Elements of this proposal will reduce some of the barriers to procuring BTM DERs: ratable flexible procurement, shared risk price structure, and leveraging private and public investment in DERs.

1.4 Objectives and Scope

The main objectives of the proposal are as follows:

1. **Streamline and scale DER procurement**

The main objective of this proposal is to present deferral tariff frameworks and elements with the goal of streamlining, scaling and increasing the quantity of DER project procurement overall. This proposal also presents ideas for streamlining the existing DIDF RFO process.

2. **Develop pilots to test the Deferral Tariff proposals and their elements**

Integral to this goal is developing a series of pilots to test the deferral tariff concepts and their elements laid out in this staff proposal. The pilot ideas described below would utilize deferral opportunities that the IOUs identify in the 2021 GNA/DDOR and DIDF process.

3. **Clarify incrementality policies for sourcing DERs for deferral**

The IOUs should clarify and align their approaches to incrementality to provide certainty to market participants and stakeholders and avoid paying twice for the same service to the ratepayers' detriment.

1.5 Guiding Principles

Based on the November 16, 2018 ALJ Ruling Directing Proposals for Distributed Energy Resources Tariffs (R.14-10-003)[13], the concepts in this proposal adhere to the following guiding design principles. Changes from the ALJ ruling text are indicated in italics and additional principles are also presented. DER tariff concepts:

[13] R. 14-10-003 - Administrative Law Judge's Ruling Directing Proposals for Distributed Energy Resources Tariffs – Attachment A - November 16, 2019. Page 1 and 2.

- Do not inherently favor traditional infrastructure investments over distributed energy resources or vice versa *while removing barriers to DERs to compete on a level playing field.*

- Provide an incentive for energy usage and market behavior (consuming, buying, and selling energy and capacity and derivative products) that is reasonably expected to reduce greenhouse gas emissions and other air pollutants.

- Provide an incentive for energy usage and market behavior (consuming, buying, and selling energy and capacity and derivative products) that is reasonably expected to ~~minimize~~ *reduce* overall energy system costs, relative to other available options, including, but not limited to:

  - Distribution costs
  - Transmission costs
  - Generation costs
  - Other costs that may overlap with the above categories, including costs associated with *operations and maintenance*, vegetation management, preventative de-energization, insurance, and any other relevant costs.

- Enable utilities to recover all Commission-approved revenue requirements equitably from both participating and non-participating customers.

- Are reasonably expected to improve the deployment *and utilization* of cost-effective distributed energy resources relative to the other mechanisms currently available.

New Proposed Guiding Principles

- Maintain technology neutrality among different DER types while recognizing that some DERs will be better able to meet certain needs than others.

- Leverage private investment in DERs to achieve deferral benefits at least at marginal cost to ratepayers. The cost of DERs must cost less than the deferral value cost cap to be selected for contracting. BTM DERs are paid for by homeowners and businesses. Deferral tariffs can leverage this private investment in DER and potentially be more cost competitive relative to paying the full cost of the DERs.

- Leverage existing DER programs not already providing deferral services such as the Self-Generation Incentive Program (SGIP) and Net Energy Metering (NEM). Leveraging existing DER programs enhances the value of those programs to ratepayers and can provide lower cost deferral solutions.

- Learn by Doing Pilots – the pilots proposed require adaptation and experimentation and a longer time horizon for evaluating results and success.

2. Clean Energy Customer Incentive

The Clean Energy Customer Incentive (CECI) provides upfront and ongoing payments to help ensure BTM DER deployment and dispatch are aligned with distribution deferral needs identified in the DIDF. The goal of this tariff is to streamline, scale, and increase the quantity of DER deferral project procurement.

The CECI offers uniform simplified terms open to any customer type where customers are incentivized to enroll in the tariff and use their DERs to operate in response to dispatch signals communicated from the utility via an approved vendor, known as a DER Service Aggregator. A tiered payment structure would be open to customers with eligible DER. Aggregators sign a contract with utilities, receive payment from the utilities, and in turn, aggregators enroll customers in the CECI and make payments to customers.

This tariff may be well suited to addressing fluctuating grid needs. For example, as the IOUs enroll customers into the tariff, the IOUs can draw from the existing pool of DERs as grid needs arise. This mitigates the IOUs' need to procure additional DERs or install traditional solutions to meet changing grid needs. The IOUs can enroll new customers if the existing pool of customers in the tariff is insufficient.[14] In addition, with aggregator bids, an individual BTM project does not have to meet 100% of grid needs, opening the field for more customer involvement.

Customers who are in existing DER programs such as SGIP and NEM could apply for the CECI, allowing IOUs to leverage and align existing programs with identified grid needs. Customers that are not part of existing programs would also be eligible. Incrementality issues related to SGIP, NEM, energy efficiency, and demand response are discussed in the "Incrementality" section of this proposal.

Benefits of CECI approach

- The simplified contract tariff format would lower transaction costs compared to the DIDF RFO process.
- The simplified contract and terms would allow a wider range of customers (i.e., smaller businesses and residential customers) to participate in the tariff. In particular, this will lead to greater procurement of BTM DER to address deferral opportunities.
- One major challenge with the current RFO process and IFOM DERs is uncertainty from long interconnection process timelines. BTM DERs have a very short interconnection time, therefore mitigating this issue.

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[14] SunRun Inc. February 15, 2019. "SunRun Inc. Proposal for Distributed Energy Resources Distribution Service Tariffs." Page 14.

- Staff believes this tariff would work well for steady load growth scenarios to address longer-term needs. It may also work well for relatively small grid needs (e.g., less than 1 MW) forecast in two or more years.
- A tiered pricing structure shares risks. For example, deployment fees would be structured as a small portion of the total deferral cost cap. If a deployment fee is paid and the planned investment is not deferred the ratepayers are less harmed then if the IOU had paid for the full cost of the DER. The DER host receives a deployment fee without the guarantee that their DER will be paid for dispatch.
- BTM procurement offers flexibility and ratability, "which can facilitate targeting and tuning deployment and dispatch to keep the identified distribution grid loading below the planned loading limit."[15]

Challenges with CECI approach

- Although the CECI would function well for steady load growth scenarios to address longer-term needs, according to the three utilities, load growth is typically not steady; it is "lumpy," with sharp increases presenting from large blocks of new load.
- Targeted deployment of large numbers of BTM DERs in a specified time frame is relatively untested.
- Coordination and communication between utilities and aggregators and between aggregators and customers could present challenges. See section "Status of IOU DERMS" for the discussion on Distributed Energy Resource Management Systems (DERMS) capabilities and implementation timeframes.
- IOU marketing partnership with approved vendors is likely needed to help them acquire customers. This could raise customer privacy, brand management, and competitive issues.

See Table 2 for a summary of CECI elements.

[15] SCE, May 24, 2019. "Southern California Edison Company's (U 338-E) Response to Administrative Law Judge's Ruling Directing Responses to Post March 4-5, 2019 Workshop Questions." Page 10-11.

Table 2. Clean Energy Customer Incentive Summary of Elements

	Clean Energy Customer Incentive
Overview	CECI offers uniform simplified terms open to any customer type where customers are incentivized to enroll in the tariff and use their DERs to dispatch according to grid needs identified in the GNA/DDOR process. This tariff is run via aggregators who sign up customers.
Prescreening Process	<u>Prescreening</u> - Required to (1) make CECI offers, (2) be listed on IOU marketing materials for the CECI <u>Prescreening Process Purpose</u> 1. Shorten offer evaluation period 2. Reduce recurring submittal requirements 3. Allow prescreened DER providers to be included in marketing materials for CECI 4. Confirm vendor capacities needed to perform expected deferral service <u>Prescreening Period</u> - Will occur July 15^{th} of each year and last 30 days. - Accepted application remain active for 2 years. Applicant reapplies after 2 years. - Also offered 30 days before each RFO or tariff subscription launch <u>Prescreening Cost</u> No cost during pilot period, IOU keep track of costs for recovery Distribution Deferral Memorandum Accounts and GRC.
Subscription Period	<u>Subscription period length</u>: Extends from date of subscription period launch until (1) enough offers accepted to meet grid need + 20% Procurement Margin or (2) date determined by IOU for contingency plan implementation
Offer Reservation, Offer Acceptance, and Procurement	<u>Offer Reservation</u> - Providers file offer reservation for portion or entirety of needed capacity at price set by IOU tariff budget. Provider shows affidavit of interest from host customers to demonstrate available capacity by end of a pre-determined reservation period. <u>Acceptance Trigger</u> - IOUs execute deferral provider contracts once 90% of deferral needs are subscribed.

	Contingency Planning - IOUs will specify contingency plan date at the subscription period launch - IOUs recover costs in their Distribution Deferral Memorandum Accounts if they are not able to procure the remaining 10% of grid need in subsequent subscription periods after the 90% acceptance trigger.
Marketing and Outreach	- IOUs serve as marketing partner to approved service aggregators. IOUs distribute marketing materials prepared by aggregators - Aggregators do not have access to individual customer information - IOUs inform customers of available CECI programs in a dedicated webpage where customers can opt-in to receive direct solicitation from approved vendors
Pricing Methods	1. Simple Method (staff recommendation): Tariff budget set at 85% of cost cap 2. Market Adjusting: for future consideration
Payment Structure	Tiered Payments 1. **Upfront** - IOUs pay providers upfront to install DER solution and commit to dispatch 2. **Test** - IOU pay providers during test events to confirm required dispatch capability 3. **Reservation** - IOUs pay providers to reserve specific amount of capacity and energy during specified timeframe 4. **Performance** - Paid when provider dispatches according to contracted criteria

2.1 Prescreening Process

Both the SOC and CECI would include a prescreening process. The purpose of DER provider prescreening is to: (1) shorten the offer evaluation period; (2) reduce the recurring submittal requirements for market participants that frequently submit tariff [16] offers; (3) allow prescreened DER providers to be included in IOU marketing materials for the CECI; and (4) confirm vendors have the capabilities needed to perform the deferral services expected. Prescreening is required for DER providers to:

a. Bid in DIDF RFOs and SOC;
b. Make CECI offers; and
c. Be listed on IOU marketing materials for the CECI.

[16] See Section 2 "Clean Energy Customer Incentive" for details on the tariff frameworks.

The IOUs would submit a Tier 2 Advice Letter for approval of prescreening application contents. The Advice Letter should be filed within 45 days of the decision approving this staff proposal. The IOUs would be required to confer with interested parties at least twice prior to filing the Advice Letter to seek consensus on prescreening application content. For potential prescreening application content, refer to "Appendix: Prescreening Application Content."

2.1.1 Prescreening Period

Prescreening would occur on July 15th each year and last for 30 days. Accepted prescreening applications would remain effective for two years, the "prescreening effective period." After two years an applicant could reapply for prescreening. Prescreening would also be offered 30 days before each RFO or tariff subscription period launch.

2.1.2 Prescreening and Marketing Costs

IOUs would not collect prescreening or marketing fees during the pilot period. Instead, IOUs would be required to track these costs for recovery in their Distribution Deferral Memorandum Accounts and may seek recovery during their General Rate Cases (GRC).[17] After pilot evaluation and analysis of the administrative and marketing costs and benefits the CPUC can determine if marketing fees and prescreening fees for both DIDF RFO/SOC bids and the CECI are justified and necessary.

2.2 Ratable Procurement of DER

The ratable concept can apply to long term IOU distribution deferral needs with a need date that is three to five years out. As PG&E explained in comments, the ratable concept means procuring incremental capacity each year to defer long term needs. This type of procurement would work in cases where load growth occurs at a "slow, steady, predictable pace."[18] This is in contrast to "procuring larger volumes at more infrequent intervals, such as procurement to meet the full need on a distribution circuit through one RFO."[19] Through the ratable approach, "the entirety of a five-year need does not have to be procured by the Contingency Date for final design construction of the year five candidate deferral project," as stated by SCE.[20]

If a candidate deferral project takes one year for final design, engineering, and construction, the IOUs would be required to procure sufficient quantities of customer-sited DERs one year ahead of the grid need date in order to defer the project by a year. Hence, the Contingency Date is also

[17] Tracked prescreening or marketing costs filed for recovery in the GRC must be itemized by deferral opportunity rather than summarized or aggregated.
[18] PG&E response to Energy Division on June 26, 2020 (Data Request No. ED_004-Q06 on June 17, 2020).
[19] PG&E response to Energy Division on June 26, 2020 (Data Request No. ED_004-Q06 on June 17, 2020).
[20] SCE, May 24, 2019. "Southern California Edison Company's (U 338-E) Response to Administrative Law Judge's Ruling Directing Responses to Post March 4-5, 2019 Workshop Questions." Page 11.

pushed out. In addition, "the procurement of DERs through this proposal would likely always require that DERs are procured beginning at a minimum of two years before the need might occur, and in sufficient quantities within the first year to successfully defer the need by at least one year."[21]

For the CECI, IOUs would set DER procurement goals for specific timeframes (e.g., 12 months) depending on grid need year. When the 90% acceptance trigger is reached with respect to the procurement goal, contracts are executed with vendors. Each subscription period remains open until either 120% of the grid need is procured or the Contingency Date occurs.

Benefits

- When coupled with the CECI, the ratable concept facilitates the participation of offers that include BTM DERs. This is a cost-effective option due to flexibility and ratability of BTM resources, "which can facilitate targeting and tuning deployment and dispatch to keep the identified distribution grid loading below the planned loading limit."[22]

Challenges

- One challenge to the ratable concept is that load growth often occurs in large increases and not a steady and predictable growth rate. In addition, such load growth capacity constraints are often mitigated through load transfers.

2.3 Subscription Period and Contingency Date

The subscription period is the period during which deferral tariff offers are accepted. The IOUs would be required to accept DER provider offers during the CECI subscription period specific to each planned investment starting when offers meet or exceed 90% of the deferral need and up to 120% of the need.

Subscription period length is dependent on the planned investment. It extends from the date of subscription period launch until: (1) enough offers are accepted to meet the grid need, including a 20% margin allowing for attrition; or (2) the date determined by the IOU for contingency plan implementation. If the utility does not receive sufficient subscription from DER aggregators by the contingency date, then the subscription period ends and the utility proceeds with the contingency plan which may include construction of the planned investment. The IOUs would provide the contingency plan implementation date at the time of subscription period launch.

It is envisioned that subscription periods would have several variations:

[21] SCE, May 24, 2019. "Southern California Edison Company's (U 338-E) Response to Administrative Law Judge's Ruling Directing Responses to Post March 4-5, 2019 Workshop Questions." Page 11.
[22] SCE, May 24, 2019. "Southern California Edison Company's (U 338-E) Response to Administrative Law Judge's Ruling Directing Responses to Post March 4-5, 2019 Workshop Questions." Page 10-11.

- Whole Procurement – the subscription period lasts until the entire deferral need is subscribed by DER Service Aggregators. This is the simpler approach.
- Ratable Procurement – several subscription periods occur sequentially to procure different increments of DERs to meet the deferral need over time in tranches.

Staff proposes that the CECI subscription periods launch on January 15, 2021 for the 2021-2022 CECI pilot. The IOUs would file a Tier 2 Advice Letter on November 15, 2021 for approval to launch one or more CECI deferral subscriptions. See Table 3 in the "Clean Energy Customer Incentive Pilots" section.

2.3.1 Cost Cap and Forecast at Subscription Period Launch

The IOUs would be required to submit their final cost caps based on the best available information with their November 15th request for approval to launch subscription periods for specific planned investments. The cost caps for each planned investment would not be updated throughout the subscription period, except as explained here.[23] This provides market certainty that enrolled DER customers would receive payments as defined at subscription period launch. Cost estimates can go up or down as the IOU refines the estimate based on site visits and additional design work.

If the grid need is cancelled based on a forecast update after the 90% offer acceptance trigger is reached, only the deployment payment would have been spent. If the grid need increases or changes during an open subscription period, the utility would be required to first seek to accommodate the change within the terms of the current solicitation. Alternatively the utility would <u>increase</u> the cost cap within the same subscription period, modify subsequent subscription periods, or add additional subscription periods to meet the change in need. The cost cap would not be adjusted downward based on grid need changes during an open subscription period.

2.4 Offer Reservation, Offer Acceptance, and Procurement

Offer reservations and proof of milestones would be utilized to demonstrate that DER Service Aggregators are able to acquire the necessary customers and have the necessary capacity available to meet grid needs when called upon. During the subscription period, the provider files an offer reservation for a portion or entirety of the needed capacity at the price and terms published by the utility for the CECI subscription period. Within an established reservation period the provider must show affidavits of interest on the part of the host customers to demonstrate the available capacity.

[23] See also Reform No. 33 in the email Ruling, Revision of Attachment A to ALJ Ruling 5/11/2020 re DIDF Reform (June 12, 2020; R.14-08-013), which states, "…Upon filing the November 15th requests for RFO launch, the IOUs shall submit their final cost cap based on the best available information at that time. From the date of RFO issuance, the cost cap for the planned investment shall not be updated prior to DER deferral contract execution or notification to Energy Division and all DPAG stakeholders that no bids were accepted."

If they do not present the affidavits by the end of the reservation period they either surrender their capacity reservation or their reservation capacity is modified to reflect the affidavits submitted.[24]

The reservation period should be established at the launch of each subscription period and should be appropriate for the length of the subscription period and size of the capacity needed. This is an important issue to vet in the DPAG prior to the launch of the subscription periods.

The intent of the reservation period is to prevent the potential issue of queue hogging or phantom projects, as described by the California Solar & Storage Association (CalSSA).[25] One potential challenge with this offer reservation approach is the lack of certainty for aggregators and customers who sign conditional agreements pending offer acceptance and contracts with IOUs. IOUs should promptly execute contracts with aggregators once the 90% acceptance trigger is reached and should also promptly pay the deployment payment once proof of operation is provided.

When total reservations reach 90% of the CECI capacity need the offer acceptance is triggered and the utility executes contracts with one or more providers. The next milestone is the deployment payment which is payable upon proof of the DERs becoming operational. The subscription period remains open until 120% of needed capacity is subscribed and contracted.

Once providers have secured a contract with the IOU, the IOUs may require additional proofs of additional project milestones to ensure that projects in each aggregation are progressing toward timely project completion. See the "Tiered Payment Structure" section below for more details on the tiered payment structure. DER providers must disclose if their customers are signed up to any other existing DER program such as SGIP and NEM.

2.4.1 Acceptance Trigger

Currently in DIDF RFOs, 100% of grid needs must be met before IOUs move forward with deferral project contract execution. Staff proposes a 90% acceptance trigger for CECI offers. If an IOU procures 90% of the grid need during the subscription period, it is likely that they will procure the remaining grid need. The subscription period would remain open and contracts executed until the full grid need plus a procurement margin of 20% is procured to account for potential attrition.

2.4.2 Contingency Planning

At the time of subscription period launch, the IOUs would be required to specify the date to initiate the contingency plan specific to each planned investment. This date typically marks the point at which the IOU is no longer pursuing the deferral, but can include other contingencies as well. If the

[24] Proof of contracts with host DER customers is also accepted to hold a reservation.
[25] CalSSA, February 15, 2019. "Distribution Services Proposal of the California Solar & Storage Association." Page 6.

acceptance trigger (e.g., 90%) results in contract execution and the IOUs do not procure the remaining 10% during a subsequent subscription period, the IOUs would recover costs in their Distribution Deferral Memorandum Account.[26]

Utilities suggest that BTM DERs be procured through contracts with aggregators no later than one year in advance of the in-service date of the planned investment to allow time for the contracted DERs to be deployed and prepared for grid services. SCE suggest that a safer approach is to begin deploying the contracted DERs two years in advance of the in–service date to ensure sufficient quantities within the first year to successfully defer the need by at least one year.

Deploying DERs two years in advance of the grid need will be challenging for the goal of deferring more near-term needs, but for grid needs that are 3-5 years out it is recommended that DER deployment begin at least two years in advance of the need with the goal of procuring DERs in sufficient quantities within the first year to successfully defer the need by at least one year. For grid needs less than 3 years out, CECI project selection should focus on grid needs that can be feasibly deferred through expedited DER procurement.

2.5 Marketing and Outreach

In the current RFO process, a critical challenge that BTM developers face to successfully meet a deferral capacity requirement is acquiring the customers necessary to host the requisite amount of capacity, leading to uncertainty in the DIDF process for BTM-focused developers. As CalSSA points out, it can be challenging to determine which specific customers are served in the footprint of the circuit or substation in question. CalSSA proposes that the utilities facilitate awareness of the deferral opportunity by including a notice to customers in the affected area as soon as possible after the Energy Division approves the deferral opportunity advice letters. There are several opportunities for providers and IOUs to cooperate and provide marketing material to target customers. This proposal is largely based on CalSSA's 2019 Distribution Services Tariff Proposal. Two approaches are offered, and Staff recommends both for the CECI.

First, Staff proposes to require the utilities to serve as a marketing partner with approved CECI DER Service Aggregators. Utilities would be required to distribute marketing materials prepared by DER providers via direct mail, bill inserts, customer billing websites, and/or emails to customers who meet the program's eligibility requirements and/or have suitable load profiles. Aggregators do not have access to information specific to each customers. The IOUs are in a better position to distribute the marketing materials in a targeted and efficient way.

Utilities should also inform customers of the available CECI programs via a program dedicated webpage on the utilities' websites. These pages will allow for any customer to opt-in to receive direct

[26] See Reform No. 51 in the *May 11, 2020 Ruling* for tracking contingency plan spending in the IOUs' Distribution Deferral Balancing Accounts.

solicitations from approved providers about available programs. One feature to include is allowing a customer to enter their zip code or account number to receive information on whether they are located in an area with an active CECI solicitation.

In order to encourage participation during the pilots, the IOUs should not charge providers for marketing. Instead, the IOUs should account for all administrative and operational costs in the utilities' Distribution Deferral Memorandum Accounts. Utilities will keep track of marketing costs during the pilot as described in the "Prescreening and Marketing Costs" section of this staff proposal.

2.6 Pricing Methods

In this section we present a CECI simple pricing method that the IOUs would be required to implement during the pilot period. Two market-driven approaches for future consideration are presented as well. Prices are in $/kw-month.

2.6.1 Simple Pricing Method (Staff Proposal)

Staff proposes that the CECI price be set at 85% of the cost cap[27]and DER providers respond to that single offer which is publicly disclosed. In the event of multiple offers, the IOUs can accept offers on a first come first serve basis provided the offers are valid. An alternative approach is the IOUs screen multiple offers for best overall fit to the deferral need. In the "Clean Energy Customer Incentive Pilots" section of this proposal, 85% of the cost cap of a planned investment is referred to as the "tariff budget."

A single price offer provides simplicity in the first round of CECI pilots and a shorter offer process overall. Despite less competition in the price category, setting the price at a certain percent of the traditional wired solution cost ensures ratepayer savings. If an offer falls through, the IOUs can accept the other qualified offers submitted.

2.6.2 Market Adjusting Pricing (For Future Consideration)

The following pricing method is based on SCE's "reverse auction" method as well as the Redwood Coast Energy Authority Community Choice Aggregation (CCA) CA Feed in Tariff.[28,29] The CECI price undergoes periodic adjustments based on market interest in the offered tariff in each price period (e.g., two-month period).

[27] CalSSA, February 15, 2019. "Distribution Services Proposal of the California Solar & Storage Association." Page 5.
[28] SCE, May 24, 2019. "Southern California Edison Company's (U 338-E) Response to Administrative Law Judge's Ruling Directing Responses to Post March 4-5, 2019 Workshop Questions." Page 9.
[29] https://redwoodenergy.org/wp-content/uploads/2019/04/RCEA-FIT-Tariff-1.pdf

The tariff budget would start at a reference point which is a certain percentage of the deferral value (i.e. 70%). In the event of undersubscription after two months (defined as procuring 0-25% of capacity need), the price would increase to 75% of the cost cap. If undersubscription continues, the price would increase up to 90% of the cost cap in the end. If offers remain at 0-25% of the required capacity, the tariff closes. In the event of oversubscription (75%-100% of capacity need), the offered price decreases in the following subscription period. If 25-75% of the capacity need is brought under contract, pricing would stay the same. IOU will make each subscription period's price available to providers by the first day of that period.[30]

Adjusting pricing to reflect market demand will lower contract costs and lead to cost savings for ratepayers. This method is also a flexible approach that can be used for the CECI and other standard offer contract procurement methods. However, multiple rounds of bidding will lengthen the procurement process, increasing risk for DER providers. The market adjusting price is not recommended by Staff at this time, but price methods that introduce more competition can be considered in the future. This method may not fit well with the CECI approach, because the subscription period is an open window for aggregators to enroll customers to subscribe available capacity at a certain price. Customer enrollment is already one of the major challenges of the CECI approach. Introducing a complex and uncertain pricing scheme is not supported at this time.

2.6.3 Simple Auction Pricing Method (For Future Consideration)

Based on PG&E's DIDF Tariff proposal, the Auction Pricing Method allows for market-driven pricing.[31] IOUs release cost caps[32] for deferral projects to inform whether providers are interested in the project. Providers then submit pricing sheets indicating their willingness to accept price levels at different percentages of the cost cap during the subscription period. When the 90% acceptance trigger is met, IOUs sign contracts with providers. The cost cap is made public to ensure a transparent and fair bidding process.

This method benefits from a single round simplified bidding process that reduces developer risk compared to a more complicated bidding process. In addition, the ability to negotiate lower cost contracts is beneficial to ratepayers and this method makes it easier for IOUs to differentiate and select offers in the event of multiple offers.

Despite the benefits to the Auction method, Staff recommends the Simple Pricing Method due to the same reasons as the Market Adjusting method.

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[30] https://redwoodenergy.org/wp-content/uploads/2019/04/RCEA-FIT-Tariff-1.pdf. Page 2.
[31] PG&E Response to ALJ's Ruling Directing Proposals for Distributed Energy Resources Tariffs – February 15, 2019. Page 14.
[32] This cap is specific to each planned investment and is the cost of the traditional wired solution investment.

2.7 Tiered Payment Structure

The CECI's payment method consists of several tiers of payment to incentivize participation in the tariff, ensure ongoing, sufficient DER capability, and pay for successful dispatch.[33] SCE, Sunrun Inc. and other stakeholders suggested a similar payment structure. Overall, a combination of upfront and ongoing payments could prove to be more cost-effective compared to traditional wired solutions capital investments. This payment structure will help ensure that dispatch occurs when and where it is needed. Performance payments would be made on a $/kW-month basis and calculated based on the cost cap. Fixed payments are appropriate for the "deployment payment" and "test payment" to simplify contracting processes. All utility payments go to aggregators and aggregators make arrangements to pay enrolled and participating customers.

1. Upfront (Deployment) Payment – IOUs pay the providers upfront to install a DER solution and commit to dispatching when called upon in accordance with the utility contract. This payment serves as an incentive to participate in the tariff and could be about 20% of the cost cap. At this point, utilities will have a list of available DERs under contract on standby.

2. Test Payment – IOUs pay providers during test events (as needed per IOU request) to confirm that they have the capability to dispatch as required during a grid need. This payment might be standard for all planned investments rather than based on the cost cap. This would not be the same as the performance payment but would ensure the customer is technically capable of dispatching when called.

3. Reservation Payment – IOUs pay providers to reserve a specific amount of capacity and energy during a specified timeframe (e.g., June through August from 4:00pm to 9:00pm). This is not the same as the performance payment but will ensure the customer is incentivized to hold capacity in reserve if called.

4. Performance Payment – This payment is given when providers dispatch according to contracted criteria. Providers are not paid if the grid need does not arise, which will increase cost-effectiveness and allow for over-procurement to address changing grid needs.

Non-Dispatchable DERs in the CECI

The CECI should maintain technology neutrality and be open to all types of DERs. The proposed tiered payment structure is oriented to dispatchable resources. For non-dispatchable resources (e.g., energy efficiency), a different payment structure is needed to enable participation on a level playing field. One approach is to pay non-dispatchable resources a deployment payment similar to the tiered structure. Since payments are not linked to performance with non-dispatchable resources, the

[33] CESA. August 19, 2020. "CESA DER Tariff Brief – Integrated Distributed Energy Resources (R.14-10-003). Page 3.

remaining tariff budget can be divided into equal annual payments for the duration of the CECI contract. If the deferral is successful then the annual payments are made. If the deferral is not being pursued and the wires solution is built then the annual payments would not continue.

2.8 Incrementality

As discussed in the *May 11, 2020 DIDF Reform Ruling*,[34] IOU approaches to incrementality need to be clarified and aligned to provide certainty to market participant stakeholders that take the time to develop and submit complex DIDF RFO bids and make offers for deferral tariffs. D.16-12-036 states in Ordering Paragraph 3f that the IOUs shall "recognize that a distributed energy resource is eligible to provide multiple incremental services and [shall] be compensated for each service." The text from the *May 11, 2020 Ruling* addressed incrementality for SGIP, NEM, and Energy Efficiency (EE) DERs in the DIDF. The text is restated below but is reframed such that it is not written in the form of question/answer documentation and with other minor edits.[35] In addition, Staff proposes clarifying text with respect to demand response.

Staff proposes each IOU adopt the text identified below for the purpose of both DIDF RFOs and deferral tariffs.

2.8.1 Self-Generation Incentive Program

Projects receiving SGIP funding should be considered fully incremental for the purposes of DIDF RFO bids and deferral tariff offers, if the provider commits to meeting the dispatch requirements pursuant to the contract for the IOU-solicited deferral services. The IOUs should be required to treat SGIP projects that provide an incremental service as fully incremental.[36]

SGIP projects must meet all applicable SGIP requirements to obtain SGIP incentives. SGIP projects do not currently have an obligation to respond to utility dispatch signals. As a result, a commitment of SGIP capacity to meet dispatch requirements should be considered an incremental service above and beyond what is compensated via SGIP. The IOUs should be required to treat any SGIP-incentivized storage project that provides the services they are soliciting as wholly incremental. The IOUs should give the provider the full payment for services procured irrespective of any additional SGIP incentives payments the provider may receive.[37]

DIDF Cost Effectiveness and SGIP

[34] See pages 77 to 80 and Reform No. 46 in the *May 11, 2020 Ruling* on DIDF reform.
[35] Text based on PG&E's *2020 DIDF RFO Questions and Answers*, February 7, 2020, at Section C, Incrementality, in the DIDF Q&A document located under the Additional Documents and Materials heading here, https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/2020-didf-rfo.page.
[36] Ibid.
[37] Ibid.

SGIP program costs should not be counted against DIDF cost-effectiveness assessments, because DIDF procurements are intended to leverage both public and private DER investments. For DIDF purposes, SGIP costs are "sunk costs" that occur regardless of the DIDF. SGIP incentivizes customers to install storage technology, but SGIP does not direct customers to defer IOU distribution investments or locate their storage in areas with grid needs. Deferral tariffs would add to (and leverage) SGIP incentives for customers that commit to siting storage in areas with grid needs and ensuring their energy storage is dispatchable as required by the IOU. This applies to both new and existing SGIP participants.

2.8.2 Net Energy Metering

Projects already compensated through NEM should be considered fully incremental for the purposes of DIDF RFO bids and deferral tariff offers, <u>if</u> the DER provider makes a material enhancement to provide the IOU-solicited deferral services (e.g., the addition of storage that commits to meeting the dispatch requirements described in the solicitation terms and pursuant to the contract for the IOU-solicited deferral services). NEM projects without material enhancement (i.e., storage) should not be considered incremental.[38]

2.8.3 Energy Efficiency

Not Already in IOU Energy Efficiency Portfolio

New EE projects should be allowed to either demonstrate incrementality subject to EE Program Administrator[39] review <u>or</u> elect to use a pre-specified "overlap factor" method. Providers that choose EE Program Administrator review would describe their proposed EE measures and targeted market segments and demonstrate that the projects do not overlap with the EE Program Administrator's existing EE programs. Program incrementality using this method could range from 0% to 100% based on EE Program Administrator review.[40]

Alternatively, providers can use a pre-specified "overlap factor" method that does not require an explicit demonstration of incrementality. With this approach, a proposed EE program is assumed to be 80% incremental. Their contribution to the grid need is discounted by 20%. For example, assuming the need is 1 MW, an EE proposal using this "haircut" method must deliver 1.2 MW.[41] The IOUs in consultation with the DPAG may propose to Energy Division to modify the overlap factor percentage and method, and Energy Division may approve modifications.

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[38] Ibid.

[39] Energy Efficiency (EE) Program Administrators include IOUs, community choice aggregators (CCAs) and Regional Energy Networks (RENs).

[40] Text based on PG&E's *2020 DIDF RFO Questions and Answers*, February 7, 2020, at Section C, Incrementality, in the DIDF Q&A document located under the Additional Documents and Materials heading here, https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/2020-didf-rfo.page.

[41] Ibid.

Already in IOU Energy Efficiency Portfolio

Projects already included in an IOU's EE program portfolio should not be considered incremental without a material enhancement for the purpose of DIDF RFO bids and deferral tariff offers. The enhancement must be clearly demonstrable above and beyond the scope of the original EE measures and installations to be considered wholly incremental.[42]

2.8.4 Demand Response

Demand Response offers are eligible for the purposes of DIDF RFOs and deferral tariffs. Such offers are fully incremental as long as the provider commits to meeting the dispatch requirements pursuant to the contract for the IOU-solicited deferral services and the commitment does not conflict with the Demand Response programs to which the provider is already subscribed.

2.9 Status of IOU Distributed Energy Resources Management Systems (DERMS)

With an increase in the number of DER deferral projects, and BTM resources in particular, the IOUs need DER communication and control functions to manage a portfolio of DERs. Without DERMS, the IOUs may not be able to dispatch individual DERs or dispatch aggregators that control aggregations of BTM DERs. Advanced use cases defined by the interconnection and smart inverter working groups for the DER Interconnection and Rule 21 proceeding (R.17-07-007) are expected to require that IOUs have the capability to send signals to DERs using DERMS. Each of the IOUs has performed multiple tests and pilots of DERMS, but DERMS experience remains limited. DER providers have partnered with utilities for those pilots, some of which have used communications technology that had not yet been widely introduced to the marketplace. Most stakeholders share a vision of DERMS becoming widespread, but there are conflicting interpretations of how quickly that can be achieved.[43] This section describes the status and capabilities of each IOU on DERMS and presents the question of what level of DERMS functionality is needed for DERs to defer planned investments.

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[42] Ibid.

[43] Rule 21 Working Group Three Final Report, June 14, 2019, California Public Utilities Commission Interconnection Rulemaking (R.17-07-007) at p. 112. Available at https://gridworks.org/wp-content/uploads/2019/06/R1707007-Working-Group-Three-Final-Report.pdf.

2.9.1 Communication with DERs Using Smart Inverters

The deadline for smart inverter advanced communications capabilities was June 22, 2020.[44] Going forward, all DER interconnection applications submitted after that date must include: (a) the capability to communicate with utilities using the Phase 2 communications protocol verified by the IEEE 2030.5 standard; (b) conformance with the Common Smart Inverter Profile that the IOUs developed in compliance with Smart Inverter Working Group Phase 2 recommendations; and (c) the capability for remote commands to reduce DER output.[45]

Similarly, the CPUC requires the utilities to develop the capability to issue and deliver commands to the DERs, and to monitor DER status and performance. However, as shown in the data response summaries provided below, the IOUs have not yet implemented DERMS and cost recovery is still being determined in their GRC applications.

2.9.2 PG&E Status

PG&E is currently in the process of developing tools and processes for near-term DERMS functionality, including low-cost telemetry to DERs and DER management for DER projects procured, as a result of DIDF RFOs. Low-cost telemetry and DER management solutions for DIDF procurements are expected to be operational in 2021. PG&E states that low-cost telemetry to DERs will be implemented system wide. DER management for DIDF procurements will be implemented in specific areas that require this functionality to address potential constraints on the system (i.e., to address grid needs to defer planned investments).[46]

For PG&E, two key functions will be available in 2021: (1) telemetry to DERs (1MW and above) between a utility IEEE 2030.5-server and a customer-owned site gateway; and (2) dispatch of DERs (via the IEEE 2030.5-server) that are providing grid services as part of the DIDF. These functions provide the foundation for future communication to aggregators.[47]

System-wide DERMS functionality would be built into PG&E's Advanced Distribution Management System via the Integrated Grid Platform they proposed in their 2020 GRC; (A.18-12-009). However, PG&E did not request funding in their 2020 GRC for system-wide DERMS. They proposed geographically targeted DERMS capabilities to address near-term telemetry and control of

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[44] Rule 21 Working Group Four Final Report, August 12, 2020, California Public Utilities Commission Interconnection Rulemaking (R.17-07-007) at p. 83. Available at https://gridworks.org/wp-content/uploads/2020/08/R21-WG4-Final-Report.pdf.
[45] Ibid.
[46] PG&E response to Energy Division on June 26, 2020 (Data Request No. ED_004-Q02 on June 17, 2020).
[47] Rule 21 Working Group Four Final Report, August 12, 2020, California Public Utilities Commission Interconnection Rulemaking (R.17-07-007) at pp. 91-93. Available at https://gridworks.org/wp-content/uploads/2020/08/R21-WG4-Final-Report.pdf.

DERs.[48] On June 11, 2020, the statutory deadline for their GRC proceeding was extended to December 13, 2020 (D.20-06-019).

PG&E has not yet provided a timeframe for system wide DERMS functionality to be in place. Regardless, PG&E stated that a focus on smart inverters presupposes that utility control is required. Instead, it is possible that DERs can be controlled by third parties (e.g. aggregators) through their own proprietary communication protocols, backhaul networks, and head-end systems, explained PG&E. Furthermore, PG&E states microgrids and the ability to control microgrid generation assets through a microgrid controller does not require smart inverter control. Not all microgrid controllers have smart inverter functionality.[49]

Finding

Starting in 2021, PG&E may have sufficient DERMS capabilities to increase the number of DERs used to defer planned investments. It is not clear when sufficient DERMS may be available for a widespread increase, but roughly 2024 can be assumed per SCE's response to Energy Division as summarized below. Third-party aggregators may be able to control DERs instead of PG&E to allow for scaling up the deferral of planned investments to a system-wide level. Staff assume that PG&E's ability to dispatch aggregators will occur in the 2021 timeframe.

2.9.3 SCE Status

SCE expects that they will have the capability to dispatch DERs in 2022.[50] SCE stated that they expect to roll out DERMS from 2021 to 2024. SCE's DERMS rollout expectation assumes that the DERMS components of their 2021 GRC are approved (A.19-08-013). A decision is expected first quarter 2021. SCE expects a first use-case for DERMS deployment in 2021/2022.[51]

Finding

Starting in 2022, SCE may have sufficient DERMS capabilities to increase the number of DERs used to defer planned investments. Sufficient DERMS may be available for widespread increase or system-wide deferral capabilities in 2024. Staff assume that SCE's ability to dispatch aggregators will occur in the 2022 timeframe.

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[48] Ibid.
[49] Ibid.
[50] SCE response to June 17, 2020 Energy Division data request.
[51] Rule 21 Working Group Four Final Report, August 12, 2020, California Public Utilities Commission Interconnection Rulemaking (R.17-07-007) at p. 91. Available at https://gridworks.org/wp-content/uploads/2020/08/R21-WG4-Final-Report.pdf.

2.9.4 SDG&E Status

SDG&E's roadmap for DERMS implementation will be included in their Grid Modernization Plan to be filed as part of their next GRC application scheduled for May 2022.[52] SDG&E is currently testing the communication capabilities needed to enable DERMS.

Finding

SDG&E will not have sufficient DERMS capabilities for the implementation of DERs to defer planned investments until after 2022. Staff assume that SDG&E ability to dispatch aggregators could occur in the 2023 timeframe.

[52] SDG&E response to June 17, 2020 Energy Division data request.

3. Clean Energy Customer Incentive (CECI) Pilots

Staff's proposed pilots focus on the process for selecting deferral opportunities and planned investments to test the CECI. Staff proposes the following three pilots:

1. Deferral Opportunity Pilot
2. Planning Area Pilot
3. Planning Area Pilot with Pooling of Planned Investment Cost Caps

Under Pilot 1, the selection of projects to apply to the CECI focuses on IOU-identified deferral opportunities in the annual GNA/DDOR filings. Under pilots 2 and 3, all planned investments within a single distribution planning area are automatically selected for CECI application if they pass the technical screen and address grid needs that occur within two to five years. Pilot 3 differs from Pilot 2 in that it includes an innovative approach to tariff funding. The combined cost caps for planned investments in the planning area would be pooled to form the tariff budget.

Staff proposes that Pilot 1 be implemented by each IOU as part of the 2021/2022 DIDF cycle with launch expected in January 2022. Staff proposes that pilots 2 and 3 be considered for future implementation after the IOUs gain experience with the CECI and more broadly roll out DERMS. Launch might occur in January 2023 and be further developed in a successor IDER and/or DRP proceeding. Staff anticipates that Pilot 1 would be the easiest to implement because it aligns most closely with the existing DIDF process. Staff expects that the scale of DER procurement would be greater under pilots 2 and 3. We describe the rationale for this expectation in the sections below.

3.1 CECI Pilot 1: Deferral Opportunity Pilot (Staff Proposal)

Pilot Purpose

Test the CECI on IOU-identified deferral opportunities in their GNA/DDOR filings and additional DPAG-identified deferral opportunities or planned investments.

Pilot Area

The pilot area would encompass the entire IOU service area, i.e., anywhere that an investment could be planned.

Pilot Period

The pilot would last approximately five years, which is the longest grid-need forecast term for most GNA/DDOR planned investments. Energy Division would determine whether to extend or reduce the pilot period. IOU annual status updates and reporting on tariff outcomes would form the basis for extending or reducing the pilot period. The IOUs, DPAG stakeholders, or Energy Division could annually identify additional planned investments to pilot the CECI which would impact pilot period length. The pilot might evolve into a formal program, and the IOUs could ultimately reduce or eliminate RFO use, if CECI outcomes are positive.

Minimum Telecommunications/DER Control Requirements

Either of the following requirements would be required to implement the CECI to procure DERs to defer a planned investment:

1. The IOU has low-cost telemetry to DERs with basic DER management capabilities in place or planned for implementation in time to adequately communicate with and manage the DERs; or
2. One or more aggregators serve the pilot area that can adequately communicate with and manage the DERs.

The "Status of DERMS" section of this proposal indicates that CECI pilots could begin as early as 2021 for PG&E, 2022 for SCE, and 2023 for SDG&E. The schedule provided in Table 3 below proposes that the CECI pilot start in January 2022.

Selection of Planned Investments to Defer by Tariff

<u>2021 GNA/DDOR Filings</u>

Within their 2021 GNA/DDORs, the IOUs would be required to propose at least one Tier 1 opportunity to pilot the CECI. The IOUs would solicit all other Tier 1 opportunities with RFOs or the SOC (refer to the "SOC Pilot" section of this staff proposal). The IOUs would also be required to propose at least two Tier 2 or Tier 3 deferral opportunities to pilot CECIs. If an IOU does not identify any deferral opportunities in their GNA/DDOR, the IOU would select at least three planned investments that pass the technical screen. The IOUs would only consider planned investments with grid needs occurring in two to five years, unless the annual review of pilot outcomes indicates that earlier grid needs could feasibly be addressed.

One of the IOU-selected Tier 2/Tier 3 opportunities should address a grid need forecast to occur in four or five years to help ensure at least one of the subscription periods is sufficiently long to test the CECI. Ideally, the IOU-selected deferral opportunities or planned investments would rank Tier 1, but for the "Forecast Certainty" metric score (i.e., year of grid need). DPAG participants may identify additional planned investments or alternative deferral opportunities from the GNA/DDORs to pilot tariffs in 2021.

<u>Scaling Up in Future GNA/DDOR Filings</u>

CECI implementation during the pilot period would scale up over time. For example, based on the annual review of pilot outcomes, the IOUs may choose to propose more than the minimum number of deferral opportunities (i.e., the 2021 GNA/DDOR requirement described above). The IOUs would continue to propose the minimum number of deferral opportunities with each GNA/DDOR filing during the pilot period, but may also propose to pilot tariffs on more than one Tier 1 opportunity and more than two Tier 2/Tier 3 opportunities. In addition, DPAG participants would seek to identify additional planned investments or alternate deferral opportunities to pilot the CECI on an annual basis.

Near-term CECI pilot results may prove that planned investments that previously failed the timing screen are feasible and cost-effective to defer using tariffs. If so, Staff expects that the IOUs may identify a larger number of deferral opportunities after a few years of successful CECI results.

DER Types Suited to this Pilot

In their GNA/DDORs, the IOUs would be required to explain why their selections for piloting CECIs have the best chance of deferring planned investments in comparison to the other options. Generally, Staff expects that planned investments selected to pilot CECIs would be best addressed by offers from BTM DER aggregators.

While a combination of BTM and IFOM DERs is possible, Staff expects aggregations of BTM DERs to be best suited to the CECI pilot. For example, if a high number of small, BTM projects are paired with a single, large IFOM project, and the IFOM project fails, the remaining BTM projects would be unlikely to meet the entire grid need. This situation would likely require the IOUs to initiate contingency plans. In comparison, the failure of a few, small BTM projects may not impact the ability of the remaining DER projects to meet the grid need.

Tariff Budget

The tariff budget would differ for each planned investment. The tariff budget is based on the cost cap specific to each planned investment at the time approval to launch the subscription period is received. It would not be updated during the subscription period. This staff proposal identifies 85% of the cost cap as appropriate for establishing the tariff budget.

Tariff Elements to Pilot

In their 2021 GNA/DDOR filing, each IOU would be required to describe their approach to implementing the CECI (e.g., prescreening application contents and marketing support plans) and testing various CECI elements (e.g., pricing method, payment structure, ratability, and others). The

IOUs would also be required to propose a methodology for assessing the cost effectiveness of CECI outcomes.

Eligibility

The IOUs should only offer Pilot 1 to providers with DERs sited at grid locations associated with one or more specific grid needs.

DPAG Role

The DPAG would deliberate about the following, among other topics related to the IOU CECI proposals filed in their GNA/DDORs:

- IOU approach to CECI implementation and elements to test.
- Additional deferral opportunities or planned investments suited to the CECI.
- IOU proposals for assessing the cost effectiveness of CECI outcomes.

Approval to Launch Subscription Periods

The IOUs would be required to file a Tier 2 Advice Letter on November 15, 2021 for approval to launch CECI subscription periods (Table 3). The IOUs would announce the subscription periods on January 15, 2022 or within 30 days of Advice Letter approval.

The IOUs, DPAG stakeholders, or Energy Division would identify additional planned investments to pilot the CECI for launch annually, and the IOUs would be required to include them in the annual (November 15th) Tier 2 Advice Letter to launch subscription periods. The IOUs would file another Tier 2 Advice Letter seeking approval not to launch CECI subscription periods for all other deferral opportunities and planned investments identified in their GNA/DDORs.[53] The additional Advice Letter gives DPAG stakeholders a procedural pathway to propose planned investments for the CECI without holding up (i.e., protesting) the approval process for IOU Advice Letters seeking approval to launch subscription periods.

[53] See Reform No. 40 in the Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework—Filing and Process Requirements (May 11, 2020; R.14-08-013).

Table 3. Schedule for CECI Pilot 1 Implementation

Activity	**Date***
Pre-DPAG 2021	
Pre-DPAG meetings and/or workshops to include planning discussion for CECI Pilot	May
DPAG 2021	
• IOU **GNA/DDOR** filings • In GNA/DDOR, IOUs identify deferral opportunities/planned investments to test CECIs **(Pilot 1)**	August 15th
DPAG activities	September - November
CECI Advice Letters submitted for approval to pilot CECI subscription periods**	November 15th
Post-DPAG 2022	
Launch **subscription periods** and IOU marketing plans implemented	January 15th (or within 30 days of DIDF Advice Letter approval if approval is after December 15th)
IOU Status and Cost-Effectiveness Reports for CECI Pilots included with GNA/DDORs for DIDF 2022-2023 Cycle	August 15th

Note:
*Where dates fall on a weekend, the activity is intended to occur on the following Monday.
**The IOUs would file a Tier 2 Advice Letter for approval to launch tariff subscription periods and another Tier 2 Advice Letter seeking approval not to launch tariff subscription periods for all other planned investments identified in their GNA/DDOR.[54]

Offer Acceptance and Contract Execution

The IOUs would be required to accept tariff offers from DER providers and execute contracts once the IOUs have addressed a percentage of the overall grid need for a planned investment. Refer to the "Offer Reservation, Offer Acceptance, and Procurement" section of this staff proposal.

The IOUs would not file an Advice Letter for approval to accept offers or for executed contracts. Instead, the IOUs would file an Information-Only Submittal (see General Order 96-B) with Energy Division for each planned investment that includes project descriptions, an offer and procurement outcomes summary, the executed contracts (in full and without redactions), and any other

[54] Ibid. See Reform No. 40.

information as required by Energy Division. Each Information-Only Submittal would include all CECI offers accepted for a single planned investment. For projects on similar timelines, the IOUs would combine Information-Only Submittals to cover multiple planned investments. This approach is similar to Reform No. 41 from the *May 11, 2020 Ruling.*[55]

Similarly, the IOUs would not be required to file Advice Letters to explain minor changes to forecast, operational requirements, cost caps, or planned investment costs that do not impact deferral viability after subscription period launch. However, should circumstances impact deferral viability at any point during the subscription period or during the executed DER contract period(s), the IOUs should be required to file a Tier 2 Advice Letter.[56]

IOU Status and Cost-Effectiveness Reports for CECI Pilots

The IOUs would report on the status and outcomes of each planned investment for which they launch CECIs in their annual GNA/DDOR filings. The IOUs would report on cost-effectiveness assessment results as of the time of GNA/DDOR filing. In general, if the sum of payments to DERs is lower than the cost-effectiveness cap for the associated planned investment, then the CECI would be considered cost effective.

For a longer-term evaluation of the CECI pilots, Staff anticipates that it will determine which of the CPUC adopted cost-effectiveness tests should be used and how.[57] Cost-effectiveness with respect to incrementality would be assessed as described in the preceding "Incrementality" section of this staff proposal above.

3.2 CECI Pilot 2: Planning Area Pilot

Staff presents CECI Pilot 2 to obtain feedback such that it can be further developed in a successor IDER and/or DRP proceeding. The characteristics of this pilot would be the same as CECI Pilot 1 except as described in the sections below.

Pilot Purpose

The purpose of this pilot would be the same as Pilot 1 but limited to deferral opportunities and planned investments located within a single distribution planning area. As the IOUs continue to

[55] Ibid. Reform No. 41 states, "The IOUs are required to file a Tier 2 Advice Letter for contract approval. If the forecast and operational requirements do not change, however, the IOUs need not file the Advice Letter for contract approval. Instead, an Information-Only Submittal (see General Order 96-B) may be filed with Energy Division upon contract execution that includes a project description, summary of bid and procurement outcomes, the executed contract (in full and without redactions), and any other information as required by Energy Division."
[56] Ibid. See Reform No. 42.
[57] Currently the CPUC has five tests for cost effectiveness: Total Resource Cost (TRC) test; Societal Cost (SC) test; Program Administrator (PAC) test; Ratepayer Impact Measure (RIM) test; and Participant Cost Test (PCT).

implement DERMS functionality system wide over the coming years, it may be most feasible to plan for pilots in planning areas where DERMS functionality is already in place. In addition, under Pilot 2, the CECI would apply to all planned investments that pass the technical screen and address grid needs occurring within two to five years.

Pilot Area

The IOUs would select one or more distribution planning areas for pilot purposes and document the selection rationale in their 2022 GNA/DDOR filings. The IOUs would each define the "planning area" within their own service territories. The term may refer to the planning area under a single transmission/distribution substation interface or a larger planning region with multiple transmission/distribution interfaces.[58]

The IOUs should seek to identify planning areas with some or all of the following features:

- Clusters of deferral opportunities and planned investments;
- High Fire-Threat Districts;
- Disadvantaged communities (DACs); and
- The minimum telecommunications/DER control requirements in place or planned to be in place in time to support the pilot.

Selection of Planned Investments to Defer by Tariff

The IOUs would be required to pilot CECIs for each deferral opportunity within the selected planning areas. They would also pilot CECIs for each planned investment in the selected planning areas that pass the technical screen and addresses grid needs occurring within two to five years.

<u>Scale of DER Procurement</u>

Pilot 2 is designed to scale up DER procurements during the pilot period with the addition of more planning areas based on annual IOU status reports and DPAG review of CECI outcomes. Pilot 2 would target a large number of planned investments within a given planning area and is expected to facilitate more DER procurements than Pilot 1 over time.

<u>DER Types Suited to this Pilot</u>

Generally, Staff expects that planned investments that the IOUs include in the pilot would be those with day-ahead capacity needs for the first year or two of the pilot. But as the IOUs gain experience,

[58] PG&E uses the term "Distribution Planning Area", which is a subset of their Distribution Planning Divisions, which are a subset of their Distribution Planning Regions.

and based on outcomes, future years of the pilot may apply tariffs to other types of grid needs in the planning area.

DPAG Role

The DPAG would deliberate about the planning area selected for the pilot, including, among others:

- Number and type of deferral opportunities and planned investments in the area; and
- Opportunities for value stacking due to proximity to fire-threat areas and disadvantaged communities.

Approval to Launch Subscription Periods

The IOUs would file a Tier 2 Advice Letter on November 15, 2022 for approval to launch CECI subscription periods within the selected planning area (Table 4). The IOUs would announce subscription periods for the planning area on January 15, 2023 or within 30 days of Advice Letter approval.

Table 4. Conceptual Schedule for Future CECI Pilot 2 and CECI Pilot 3 Implementation

Activity	Date
Pre-DPAG 2022	
Pre-DPAG meetings and/or workshops to include planning discussion for CECI Pilot	May
DPAG 2022	
• IOU **GNA/DDOR** filings • In GNA/DDOR, IOUs identify planning areas to pilot CECIs **(Pilot 2 and Pilot 3)**	August 15th
DPAG activities	September-November
CECI Advice Letters submitted for approval to pilot CECIs in the selected planning areas*	November 15th
Post-DPAG 2023	
Launch **subscription periods** and IOU marketing plans implemented	January 15th (or within 30 days of DIDF Advice Letter approval if approval is after December 15th)
IOU Status and Cost-Effectiveness Reports for CECI Pilots included with GNA/DDORs for DIDF 2023-2024 Cycle	August 15th

Note:
*Where dates fall on a weekend, the activity is intended to occur on the following Monday.
**The IOUs would file a Tier 2 Advice Letter for approval to launch Pilot 2 within one planning area and another Tier 2 Advice Letter for approval to launch Pilot 3 within a second planning area.

3.3 CECI Pilot 3: Planning Area Pilot with Pooling of Planned Investment Cost Caps

Staff presents CECI Pilot 3 to obtain feedback such that it can be further developed in a successor IDER and/or DRP proceeding. The characteristics of this pilot would be the same as CECI Pilot 2 except as described in the sections below.

Pilot Purpose

The purpose of this pilot would be the same as Pilot 2, but the IOUs would structure it such that the combined cost caps of all planned investments in the planning area would form the basis of the tariff budget. This approach diverges from the pricing method that Staff proposed to set the CECI budget (at 85% of the cost cap of a single planned investment).

The pool of funds under Pilot 3 allows the IOUs to offer deployment payments to all providers that site new DERs within the planning area. The intent is to test the ability of DERs to lower overall planning area loads and, in doing so, reduce the number and/or size of traditional planned investments and forecast volatility. The IOUs would only offer test, reservation, and performance payments to new and existing DERs that can directly support specific grid needs and only if the need materializes.

Pilot Area

The IOUs would select a planning area different than the one selected for Pilot 2.

Tariff Budget

The IOUs would pool the costs of traditional investments planned throughout a given planning area and use them as a basis for developing CECI budgets for this pilot. The budget could be equal to the combined cost caps, combined unit costs, or a portion of these combined costs. Staff proposes that the IOUs use the combined cost caps for all planned investments as the basis for the tariff budget.

This approach to establishing the tariff budget is designed to align more closely to how categories of planned investments are approved in a GRC. The IOUs allocate pools of GRC-approved funds to build traditional infrastructure. In a GRC, costs are not typically capped for individual distribution investments, rather, they are capped for an entire category of investment. Hence, DER costs would not be capped based on a single planned investment but a pool of planned investment cost caps.

Planned investments included in the pool must pass the technical screen and address grid needs that occur within two to five years. American Association of Cost Engineers level 5 cost estimates (at minimum)[59] would be required in the annual GNA/DDORs for all planned investments in the planning area. The pooled tariff budget would be updated annually as: (1) planned investment cost estimates are refined; (2) planned investments exit from the pool because circumstances trigger the contingency or grid needs change; and (3) the IOUs identify new, tariff-eligible planned investments for the planning area. Contracts executed prior to the annual tariff budget change would not be impacted.

Testing an Alternate Approach

The tariff budget for CECI Pilot 3 diverges somewhat from the method Staff proposes in other sections of this proposal. Staff proposed that the tariff budget be 85% of the cost cap of a single

[59] American Association of Cost Engineers provides an industry standard for cost estimations applied to the electric power sector. See Reform No. 44 from the *May 11, 2020 Ruling* as updated by email Ruling on June 12, 2020.

planned investment and allocated 20% of the budget for deployment payments (see "Simple Pricing Method" and "Tiered Payment Structure" sections).

CECI Pilot 3 applies the Simple Pricing Method but sets the budget at 100% of cost caps and allocates 15% of the budget to deployment payments. The deployment payment would be available to all new DERs within the planning area, rather than limited to DERs sited to directly address grid needs. This would test the ability of a wider spread of DER deployments to reduce the peak load throughout the entire planning area and, in doing so, reduce the number and/or size of traditional planned investments and forecast volatility. It also allocates the entire 85% of cost caps to test, reservation, and performance payments. This further incentivizes providers to site DERs in areas that help the grid and perform when dispatched.

Eligibility

All providers siting new DERs within the planning area would be eligible for the deployment payment. New and existing DERs sited at grid locations associated with a specific grid need would be eligible for test, reservation, and performance payments.

Payments

The budget for deployment payments would be 15% of the combined budget for the planning area. The subscription period and 90% acceptance trigger concepts would not apply to the deployment payments. The remaining 85% would form the budget for test, reservation, and performance payments, and the subscription period and acceptance trigger concepts would apply. One hundred percent of the combined cost caps would be allocated to payments, which differs from the approach Staff proposes in other sections of this proposal (see "Testing an Alternate Approach," above).

<u>Cost Effectiveness</u>

Staff anticipates that Pilot 3 would be cost effective, in part, because only 15% of the combined costs caps would be used for guaranteed, deployment payments to new DER providers. The IOUs would only pay the remaining 85% as grid needs materialize (i.e., test, reservation, and performance payments). In general, if the sum of payments to DERs during the pilot period is lower than the combined cost caps of avoided or deferred planned investments within the planning area, then the CECI is cost effective.

<u>Scale of DER Procurement</u>

With Pilot 3, Staff anticipates that the scale of DER procurements would be greater than under Pilot 2 because all new DERs sited within the planning area would receive the deployment payment, and the IOUs would allocate 100% of the combined costs caps to the tariff budget. Staff expects that

Pilot 3 would result in the greatest amount of DER procurement in comparison to the other two CECI pilots. This is especially true if Pilot 3 expands to include additional IOU planning areas based on the annual review of CECI and pilot outcomes.

4. RFO Streamlining/Standard Offer Contract

The CPUC continues to explore ways to streamline the competitive solicitation framework by adopting and developing proposals that will reduce the amount of regulatory filings and decrease the time it takes to launch a DIDF RFO, select a developer and execute a contract for DER services.

4.1 RFO Streamlining

To provide sufficient certainty and lead time for DER developers, aggregators, and service providers, the CPUC should allow for the procurement of a variety of DERs to meet Tier 1 candidate deferral needs identified in the DDOR without the IOUs having to gain approval to launch RFOs. By eliminating the IOU's requirement to file two Tier 2 Advice Letters and by launching RFOs five months earlier in the solicitation schedule, the IOUs will be able to expeditiously procure DERs to defer grid needs.

At the launch of the DPAG on August 15, 2021, the IOUs would be authorized to launch RFOs for all Tier 1 projects the IOUs identified in their DDOR reports. The IOUs would no longer submit a Tier 2 Advice Letter seeking approval to launch RFOs on Tier 1 deferral opportunities. The IOUs will continue to participate and host DPAG meetings for stakeholders focused on Tier 2 and 3 deferral candidates identified in the IOUs DDOR reports. If additional deferral candidates are identified as Tier 1 opportunities during the DPAG, the IOUs would be authorized to launch RFOs for those identified projects without seeking further CPUC approval.

The IOUs would still be required to submit an Advice Letter by November 15 seeking approval to not launch an RFO for any remaining candidate deferral opportunities or other planned investments (Reform No. 40).[60] The phrase, "or other planned investments," will be added to Reform No. 40.

Developers who have participated in the IOUs prescreening process, as Staff describes in the "Prescreening" section of this proposal, would be eligible to participate in the RFO solicitation beginning on August 15, 2021. The IOUs do not currently charge a fee to developers to bid on DIDF RFOs, and no prescreening fee would be collected from providers. For more information, please refer to the "Prescreening" section of this staff proposal.

The IOUs are no longer be required to explain minor changes to forecast operational requirements, cost caps, or planned investment costs that do not impact deferral viability after the RFO launch and throughout the contract period as set forth in the *May 7, 2019 Ruling* (Reform No. 42).[61] Should circumstances impact deferral viability, or trigger the contingency plan at any point after RFO

[60] Administrative Law Judge Ruling Modifying the Distribution Investment Deferral Framework Filing and Process Requirements, Attachment A, May 7, 2020. Page 96.
[61] Ibid.

launch or during the DER contract period, the IOUs would be required to file a Tier 2 Advice Letter.

IOUs are no longer required to file a Tier 2 Advice Letter for contract approval (Reform No. 41)[62] if the forecast and operational requirements do not change. In lieu of seeking contract approval from the Energy Division, the IOUs should be required to file an Information-Only Submittal (see General Order 96-B) with the Energy Division upon contract execution that includes a project description, summary of bid and procurement outcomes, the executed contract (in full and without redactions), and any other information as required by Energy Division.

See Table 5 to review the current DIDF RFO solicitation schedule compared to the revised RFO solicitation schedule.

4.2 Standard Offer Contract Pilot

The Standard Offer Contract (SOC) is the sourcing mechanism to be piloted in the 2021 DIDF to streamline the RFO process for IFOM DERs for needs more than two years out.[63] The SOC is likely best suited for larger scale providers of IFOM DERs, but can also be used by aggregators of multiple small BTM DERs.

4.2.1 Pilot Period

The pilot would last approximately five years and the IOUs would be required to launch at least one Tier 1 candidate deferral opportunity during each DIDF cycle. Energy Division will determine whether to extend or reduce the pilot period IOU annual status updates and reporting on tariff outcomes would form the basis for extending or reducing the pilot period. The IOUs, DPAG stakeholders, or Energy Division may annually identify additional planned investments to pilot the SOC which will impact pilot period length. The pilot might evolve into a formal program, and the IOUs could ultimately reduce or eliminate the traditional RFO use if SOC outcomes are positive.

4.2.2 Pricing and Procurement Mechanism

Beginning August 15, 2021, IOUs should be required to select one Tier 1 candidate deferral opportunity to procure DERs through a SOC. The IOUs will provide notice of the DER services needed to defer planned investments along with a price sheet to procure the DER services. Prescreened developers will indicate the quantity of the DER services they are willing to provide at the prices offered. Initially, Staff expects that the IOUs will use the SOC to procure DERs to

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[62] Ibid.
[63] SCE, February 15, 2019, "Response of Southern California Edison Company (U 338-E) to Administrative Law Judge's Ruling Directing Proposals for Distributed Energy Resources Tariffs." Page 2.

address day-ahead capacity needs. As the IOUs gain experience implementing the SOC, they will seek to address other types of grid needs with the SOC.

Simple Auction Pricing Method

Based on PG&E's DIDF Tariff proposal, the Simple Auction Pricing Method allows for market-driven pricing. IOUs release cost caps for deferral projects to inform whether providers are interested in the project. Providers then submit pricing sheets indicating their willingness to accept price levels at different percentages of the cost cap during the subscription period. When the 90% acceptance trigger is met, IOUs sign contracts with providers. The cost cap is made public to ensure a transparent and fair bidding process.

Procurement Method

The language within the standardized offer contract should be based on the existing TNPF contract, already developed via the IDER proceeding.[64] The SOC TNPF will be project specific and will set forth the terms and conditions, identify compensation, and address contingencies including non-performance of the developer in providing distribution services. The IOUs would confer with interested partied at least two times prior to finalizing the SOC TNPF to achieve consensus on the standard terms and conditions. After consulting with interested parties, the IOUs will develop a SOC TNPF with standard terms and conditions that are not modifiable in the first year of the pilot. Any revisions proposed for the SOC TNPF thereafter, would be included in the IOUs Tier 2 Advice Letter as required by the IDER proceeding.

4.2.3 Marketing and Outreach

Initially, Staff expect the SOC will likely be subscribed by developers of IFOM DERs, thus a discussion of marketing and outreach to individual customers is not included here. However, if SOCs are considered for BTM DERs then the marketing and outreach approach described in the "CECI Marketing and Outreach" section of this Staff proposal would apply.

[64] See D.18-02-004 at 42.

Table 5. Example of Streamlined DIDF & RFO Solicitation Schedule compared to current RFO Solicitation Schedule (this table only applies to RFOs and SOC Pilot)

Current RFO Schedule	Current RFO Activity	Revised RFO Activity
Spring 2021	1) DIDF Reforms Ruling 2) Pre-DPAG	1) No change 2) No change 3) Tier 2 Advice Letter detailing the elements of each IOUs Prescreening Application (90 days after Decision)**
Spring/Summer 2021	Pre-DPAG continued	1) No change 2) Prescreening begins (July 15, 2021)
August 15, 2021*	1) GNA/DDOR filings, Final IPE Plans circulated 2) DPAG period begins	1) No change 2) No change 3) IOUs launch RFOs 3) IOUs launch SOC pilot for one Tier 1 deferral candidate
September 5, 2021*	IPE Preliminary Analysis of GNA/DDOR Data Adequacy for all three IOUs	No change
September -November 2021	1) DPAG meetings 2) Tier 2 Advice Letter seeking approval to launch RFO (November 15, 2021*) 3) Tier 2 Advice Letter for not launching RFOs for all Tier 2 and Tier 3 opportunities (November 15, 2021*)	1) DPAG meetings 2) Advice Letter eliminated. 3) No change
December 2021 to Spring 2022	1) Post-DPAG 2) Review and approval of Advice Letter seeking approval to launch RFOs and Advice Letter for not launching RFOs for all Tier 2 and Tier 3 opportunities 3) DIDF reform process	1) No change 2) One Advice Letter eliminated. Review of remaining Advice Letter seeking approval not to launch an RFO for Tier 2 and Tier 3 opportunities 3) No change

January 2022	Annual DIDF reform comments due.	1) No Change 2) If DPAG identifies opportunities to elevate to Tier 1, launch a second round of RFOs
February 2022	1) IPE Post DPAG Report covering all three IOUs 2) Comments on IPE Post-DPAG Report and replies to January 20 reform comments due	1) No change 2) No change 3) Information-Only Submittal notifying CPUC of executed contracts for RFO solicitations and SCO pilot[65]

Note:
*Where dates fall on a weekend, the activity is intended to occur on the following Monday.
**Not expected to be required annually.

[65] Approval to launch occurs on August 15, hence February 15th is 6 months per proceeding R.14-08-013, *Ruling on the Application of the Competitive Solicitation Framework for Distribution Investment Deferrals in the Distribution Resource Planning Proceeding*, November 19, 2018.

5. Emergency Dispatch for System Reliability Program

As the CPUC identifies new grid services in various proceedings (e.g., the Microgrids and Resiliency proceeding), these future grid services could be procured through the DER sourcing mechanisms presented in this proposal as additional value streams. In light of recent power outages, Staff recommends that the IOUs add an Emergency Dispatch for System Reliability Program as a near-term priority for an additional value stream to be added to the CECI. The emergency dispatch program could be used when the California Independent System Operator (CAISO) issues a curtailment notice.

In the CECI program BTM batteries could provide emergency dispatch during a system emergency. When BTM customers join the CECI program through their provider of choice, their provider could offer them a chance to opt into this additional Emergency Dispatch Program (EDP). This concept is presented here for initial feedback and exact details should be developed later including dispatch notice and dispatch requirements, trigger conditions, guidelines for capacity determination, compensation mechanism, and the treatment of the available capacity relative to the Resource Adequacy framework.

Appendix: Prescreening Application Content

The list of potential prescreening application content described below is not intended to be comprehensive. Each IOU may have unique prescreening application details. IOU-specific details will be reviewed during the DPAG each year as determined by Energy Division.

Company Name and Contract Information	• Legal, registered company name and headquarters location • Parent company details, if subsidiary, and listing of all affiliates • Principal and backup points of contract • Authorized agent for bids and offers

Identification of Procurement Interest Areas and IOU Marketing Support	• Indicate if interested in one or both of the following:
	  ○ DIDF RFO
	  ○ Deferral Tariffs (also indicate if interested in being included in IOU marketing materials for Deferral Tariffs)
	• Identify preferred geographic locations (i.e., preference for deferral opportunities located in specific counties, cities, etc., if any)

DER Preferences and Performance Expectations	• Identify grid need types expected to be addressed by bids/offers and any preference for specific grid needs:
	  ○ Capacity
	  ○ Reliability
	  ○ Resiliency
	  ○ Voltage support
	• Overview of service types and DER technologies expected to be offered, such as:
	  ○ Demand response
	  ○ Energy storage
	  ○ Energy efficiency
	  ○ Permanent load shift
	  ○ Renewable distributed generation
	  ○ Non-renewable distributed generation (must specify all potential types)
	  ○ Electric vehicles and/or chargers
	• Performance characteristics and guarantees
	  ○ Describe the capabilities of DERs to be provided
	  ○ Response may be specific to deferral opportunities or other planned investments identified in the GNA/DDOR

Experience	• Description of experience deploying DER technologies, including:
	  ○ Deployment dates and locations
	  ○ Purpose of deployments
	  ○ Types of DERs deployed
	  ○ IFOM and BTM deployments
	  ○ Customer types served (residential, industrial, etc.)
	  ○ Project size
	  ○ Partnerships (e.g., with aggregators, agencies, utilities, or local communities)

	◦ DER marketing • Description of other relevant energy experience
Company Details and Organizational Information	• Summary of company background, history, and service types • Organizational and personnel structure details
Company Service Areas	• States licensed to do business and license numbers • State where incorporated/formed and authorized to do business • Office locations • Workforce locations • Geographic areas currently served including numbers of and types of customers • Recent or planned service areas
Initial Screening of Creditworthiness and Financial Information	• Statement of credit rating, issuing bank, and demonstration of DER provider's creditworthiness • Year-to-date and three prior years of audited financial statements
Compliance and Confidentiality Agreements	• Agreement to comply with all DIDF RFO and/or deferral tariff requirements • Confidentiality terms and conditions, non-disclosure agreement

(END OF ATTACHMENT A)