January 10, 2017
Agenda ID #15474
Ratesetting

TO PARTIES OF RECORD IN RULEMAKING 14-08-013 ET AL. AND
APPLICATION 15-07-005 ET AL.:

This is the proposed decision of Administrative Law Judge Peter Allen. Until and
unless the Commission hears the item and votes to approve it, the proposed decision
has no legal effect. This item may be heard, at the earliest, at the Commission’s
February 9, 2017 Business Meeting. To confirm when the item will be heard, please see
the Business Meeting agenda, which is posted on the Commission’s website 10 days
before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in
closed session in advance of the Business Meeting at which the item will be heard. In
such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily
Calendar, which is posted on the Commission’s website. If a Ratesetting Deliberative
Meeting is scheduled, ex parte communications are prohibited pursuant to
Rule 8.3(c)(4)(B).

/s/ RICHARD SMITH for
Karen V. Clopton, Chief
Administrative Law Judge

KVC:lil

Attachment
BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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Appendix A – Reporting Requirements and Schedule for Demonstration
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Appendix B – Metrics for Demonstration Projects C, D and E
Summary

This decision addresses Track 2 Demonstration Projects C, D and E proposed by Pacific Gas and Electric Company (PG&E) in Application (A.) 15-07-006, Southern California Edison Company (SCE) in A.15-07-002, and San Diego Gas & Electric Company (SDG&E) in A.15-07-003, as well as the demonstration projects proposed by Center for Sustainable Energy and Bloom Energy. PG&E’s proposed Demonstration Projects C and D are approved. SCE’s proposed Demonstration Projects C and D are approved. SDG&E’s proposed Demonstration Projects C and E are approved. Approved Demonstration Projects are subject to certain conditions and modifications. The other proposed projects are not approved. This decision resolves the current Track 2 issues; these proceedings remain open for consideration of other issues.

1. Background

The Order Instituting Rulemaking (OIR) that opened Rulemaking (R.) 14-08-013 included the question:

10) Should the DRPs [Distribution Resources Plans] include specific measures or projects that serve to demonstrate how specific types of DER [Distributed Energy Resources] can be integrated into distribution planning and operation? If so, what are some examples that IOUs [Investor Owned Utilities] should consider? (OIR at 7.)

The February 6, 2015 Assigned Commissioner’s Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning (Guidance Ruling) directed the utilities to propose DER-focused demonstration projects, and provided more detailed guidance regarding what should be included in those demonstration projects. (Guidance Ruling, Attachment 1 at 5-7.) The utilities
submitted their proposed demonstration projects in the applications filed on July 1, 2015, and in supplemental filings on June 17, 2016.

The January 27, 2016 Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, Including Deconsolidation of Certain Proceedings and a Different Consolidation of Other Proceedings (Scoping Memo) identified the primary focus of Track 2 as being the design and authorization for Demonstration Projects C, D and E. (Scoping Memo at 8.)

The Demonstration Projects were described by the Scoping Memo

Project C: Demonstrate DER Locational Benefits. This project will validate the ability of DER to achieve net benefits consistent with the LNBA [Locational Net Benefits Analysis].

Project D: Demonstrate Distribution Operations and High Penetrations of DERs. This project calls for the utilities to integrate high penetrations of DER into their distribution planning operations. The utilities must: a) assess locational benefits and values of DER at the substation level using ICA [Integrated Capacity Analysis] and LNBA across multiple circuits; b) demonstrate the operations of multiple DER in concert; c) coordinate operations with third parties and customers; d) develop and explain the methodology for selection of DER types used in the project; and e) utilize both third-party-owned and utility-owned resources.

Project E: Demonstrate a microgrid where DERs (both customer-owned and utility-owned) serve a significant portion of customer load and reliability services. This project will demonstrate the use of a DER management system for controlling the resources. The project will develop, document, and implement a methodology for construction and

1 SDG&E had originally proposed an additional Demonstration Project F, but that proposal is no longer under consideration. Demonstration Projects A and B were addressed in Track 1, and were authorized by an Assigned Commissioner’s Ruling issued on May 2, 2016.
operation/dispatch of the DER portfolio. The project will include both third-party-owned and utility-owned resources. (Id at 8-9.)

A May 17, 2016 ruling modified the schedule for Track 2, provided the parties an opportunity to submit revised proposals on June 17, 2016, set workshops for June 28 and 29, 2016, and allowed for post-workshop comments. Per a July 6, 2016 e-mail ruling, post-workshop comments were filed on July 22, 2016 and reply comments on July 29, 2016. In their July 29, 2016 reply comments, the Commission’s Office of Ratepayer Advocates (ORA) requested evidentiary hearings. Evidentiary hearings were held on August 10 and 11, 2016, and post-hearing comments were filed on August 26, 2016.

2. **Procedural Issues**

SDG&E filed a motion to withdraw its proposed Demonstration Project F, which was granted during the evidentiary hearings. (Transcript, Vol. 1 at 4-5.) SDG&E’s proposed Demonstration Project F is no longer under consideration in this proceeding at this time.

3. **Discussion**

3.1. **Demonstration Project C**

Demonstration Project C is intended to demonstrate DER locational benefits. This project will validate the ability of DER to achieve net benefits consistent with the LNBA. (Scoping Memo at 8.)

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2 Motion To Withdraw Optional Demonstration Project F Of San Diego Gas & Electric Company, filed on July 28, 2016.
3.1.1. PG&E

PG&E proposes to use its Chico 12 kilovolt (kV) Distribution Planning Area (DPA) as the site for its Demonstration Project C. (PG&E June 17, 2016 Revised Proposal at A-6-7.) PG&E describes the Chico DPA as follows:

The Chico DPA serves approximately 125,000 electric customers and is an area within the PG&E service territory where there are multiple locations that are projected to be distribution capacity constrained in the next five years. Specifically, this area is projected to experience distribution transformer overloads from three different substations. To ensure sufficient capacity is available in the future, PG&E has identified that additional distribution capacity, which includes installation of an additional substation transformer and construction of a new distribution feeder to ensure safe and reliable electric service. In addition, the DPA is home to a diversified customer base including residential, small and medium business, large commercial industrial, government, schools and hospitals and both agricultural water pumping and food processing. (PG&E June 17, 2016 Revised Proposal at A-6.)

ORA appears generally supportive of PG&E’s choice of the Chico DPA for Demonstration Project C. Specifically, ORA likes that the area chosen for PG&E’s Demonstration Project C aligns with its proposed area for Demonstration B:

Since PG&E uses the same project area to evaluate its LNBA and DER procurement to measure the LNBA of the site, the LNBA value calculated through Demo B should provide a proper metric to measure the success of the LNBA to predict the value DER is able to provide through DER solicitation and deployment. (ORA July 22, 2016 Comments at 9.)

The Utility Reform Network (TURN) largely focuses its comments on Demonstration Project C on what it calls the “non-DER procurement” costs, and recommends that for each utility those costs should be under $2 million. (TURN
July 22, 2016 Comments at 5-6.) PG&E’s non-DER procurement costs are $1.75 million. As a result, TURN observes that: “Only PG&E provided total costs (for non-DER procurement) that appear reasonable and within the scope of what is necessary for Demo C.” (TURN July 22, 2016 Comments at 5.)

Other parties either generally supported or were silent on PG&E’s proposed Demonstration Project C. (See, e.g., Green Power Institute (GPI) July 22, 2016 Comments at 2.) PG&E appears to have chosen a reasonable location with reasonable costs. We approve PG&E’s proposed Demonstration Project C.

### 3.1.2. SCE

SCE describes its proposed Demonstration Project C as follows:

Since the initial DRP filing, SCE has studied the PRP [Preferred Resource Pilot] region and identified the new El Toro Marine base area residential development as the most suitable location within this region for the Demonstration C project. This area is served by four circuits (Hine, Paragon, [fn. omitted] Keeline and Elden) from the Irvine substation. The additional load expected from the new development and the growing region is anticipated to drive the need for traditional distribution system upgrades to address circuit capacity and duct bank heating issues. SCE believes that this situation serves as a good field opportunity to test the ability of DERs to achieve net benefits consistent with the LNBA methodology. (SCE June 17, 2016 Comments at 3-4.)

Parties are generally supportive of SCE’s proposed Demonstration Project C. (See, e.g., GPI July 22, 2016 Comments at 2, Environmental Defense Fund (EDF) July 22, 2016 Comments at 3.) The Commission appreciates that SCE has chosen an area that has a high anticipated load growth and that SCE will leverage third-party resources already acquired to support the PRP to the extent possible.
At the same time, however, SCE’s cost estimate for its Demonstration Project C ($9.3 million, including $6.5 million for “equipment and services”) is higher than the cost of PG&E’s and SDG&E’s Demonstration Project C proposals. TURN argues that SCE’s “equipment and services” costs are inflated and not justified, and are unnecessary to achieve the goals of Demonstration Project C. (TURN August 26, 2016 Comments at 2.) TURN has proposed a $2 million non-procurement cost cap for all utilities for Demonstration Project C. (Id.)

SCE has not adequately explained the basis for its costs for Demonstration Project C, particularly its high “equipment and services” costs. We cannot find those costs to be just and reasonable. We will apply TURN’s recommended $2 million cap to SCE’s “equipment and services” costs (a reduction of $4.5 million from SCE’s proposed budget of $6.5 million), and we reduce SCE’s proposed other costs by the same proportion.³ This results in a total budget of just under $3 million, compared to SCE’s proposed budget of $9.3 million. Accordingly, SCE’s proposed Demonstration Project C is approved, but with a cap on non-procurement costs of $3 million.

3.1.3. SDG&E

SDG&E proposes to use two circuits for its Demonstration Project C: Circuit 701 connected to Mission Substation, and Circuit 470 connected to Felicita Substation. According to SDG&E, Circuit 701 is highly loaded, and already has a large number of smart inverters connected to the circuit as a result of a separate

³ Those other costs are: Design and Engineering $850,000, DER Deployment Management $650,000, Measurement & Validation (Data Analysis) $850,000 and Project Management $450,000, which total $2.8 million. (SCE’s June 17, 2016 Comments at 12.) Reducing these costs proportionately to the reduction in the “equipment and services” costs results in a total of $860,000.
smart inverter pilot project, while Circuit 470 has a forecasted capacity deficiency due to load growth in the area, and is the same circuit that SDG&E has designated for Demonstration Project B. (SDG&E June 17, 2016 Responses, Attachment 1 at 5-6.)

TURN, while expressing general support for Demonstration Project C, criticizes the cost and the utility-owned storage component of SDG&E’s proposal. TURN recommends a cost cap of $2 million per utility in non-procurement costs for Demonstration Project C, and notes that without the utility-owned storage component, SDG&E’s proposal would cost $1.8 million. (TURN July 22, 2016 Comments at 5.) The utility-owned storage proposed by SDG&E would cost $4.6 million, for a total cost of $6.4 million, leading TURN to question whether SDG&E’s proposal is consistent with the guidance that the utilities use a “minimum-cost DER portfolio.” (Id. at 5-6.) TURN also questions whether SDG&E’s proposal to add additional utility-owned storage is consistent with the guidance that Demonstration Project C employ services from customer and/or third party DERs. (Id. at 6.)

While in general SDG&E’s proposed Demonstration Project C is reasonable, we agree with TURN that the inclusion of an overly-large utility-owned storage component is inappropriate, as in this proceeding the Commission is looking for a more technology-agnostic approach, and third-party owned storage or other DER resources may turn out to be more cost effective. Accordingly, we approve SDG&E’s proposed Demonstration Project C, but remove the $4.6 million for utility-owned storage from the non-procurement budget.
3.1.4. Schedule

A number of parties were critical of the utilities’ proposed schedules for implementing Demonstration Project C. In particular, they argued that the timelines proposed by the utilities were far too lengthy, and that it is important to obtain information from Demonstration Project C results earlier than would occur under the utilities’ timeline. (See, EDF July 29, 2016 Comments at 2, Clean Coalition July 29, 2016 Comments at 3, Vote Solar August 26, 2016 Comments at 2.)

Because Demonstration Project C is intended to validate the ability of DER to achieve net benefits consistent with the LNBA, getting timely results from Demonstration Project C is in fact a key foundational step. Accordingly we will expedite the implementation of Demonstration Project C, including requiring the utilities to commence the projects within 30 days of approval of this decision, leveraging existing DERs first (both utility-owned and non-utility-owned) before procuring new DERs, an expedited procurement and approval process for new DERs, and setting a schedule for the timely filing of interim and final reports.

Assuming construction of new DERs is needed, this schedule requires the final report to be due within 2.5 years from approval of this decision. The schedule also requires the utilities to file three progress reports after commencement of data gathering for the projects. The utilities are directed to work with Energy Division to develop the content of these reports, and these reports shall be filed with Energy Division as Information-Only filings and served on the appropriate service list(s). The complete revised schedule for Demonstration Project C is attached as Appendix A.
3.2. Demonstration Project D

The Scoping Memo for this proceeding described Demonstration Project D as follows:

Demonstrate Distribution Operations and High Penetrations of DERs. This project calls for the utilities to integrate high penetrations of DER into their distribution planning operations. The utilities must: a) assess locational benefits and values of DER at the substation level using ICA and LNBA across multiple circuits; b) demonstrate the operations of multiple DER in concert; c) coordinate operations with third parties and customers; d) develop and explain the methodology for selection of DER types used in the project; and e) utilize both third-party-owned and utility-owned resources. (Scoping Memo at 8.)

3.2.1. PG&E

PG&E’s proposed Demonstration Project D is described as follows:

The proposed location for this demonstration is PG&E’s Huron Substation, which is located within PG&E’s Gates DPA. Huron Substation was selected due to its high penetration of DERs against this area’s distribution capacity. […]

Under projected 2020 peak demand conditions, the Huron distribution transformer is projected to overload up to 20% of the thermal capacity during summer months, while minimum demand conditions coupled with peak PV generation output would cause the Huron transformer to overload in the reverse flow direction during winter months.

Furthermore, this area was selected due to its unique loading profile that is forecast to resemble the “duck curve” that includes high distributed generation output during peak solar production hours and high peak demand during the evening hours. (PG&E June 17 Revised Proposal at A-14.)

ORA has expressed concern about PG&E’s proposed Demonstration Project D, particularly that PG&E has not provided adequate information to date,
and that its Demonstration Project D should not be approved until PG&E updates its proposal with significantly more information. (ORA July 22, 2016 Comments at 26-29, 34-36.) TURN raises a similar concern, arguing that PG&E’s (and SDG&E’s) proposed Demonstration Project D requires additional evaluation to ensure coordination with existing DER deployment and pilot projects. (TURN July 22, 2106 Comments at 7.) GPI, however, conditionally supports PG&E’s proposed Demonstration Project D. (GPI July 22, 2016 Comments at 2, 16.)

The cost of PG&E’s proposed Demonstration Project D is $2.1 million plus DER procurement costs. (PG&E July 22, 2016, Attachment 1.) This is the lowest total cost of any of the utility proposals for Demonstration Project D (SCE’s proposal has a lower incremental cost), and in general PG&E’s proposal is consistent with the Commission’s guidance. PG&E’s proposed Demonstration Project D (and proposed schedule) is approved.

The Commission agrees with ORA’s recommendations that the utility leverage existing RD&D projects to minimize project costs and accelerate learnings. Existing DERs are to be utilized before new procurement is made.

### 3.2.2. SCE

SCE originally proposed to use its Johanna Jr. substation area for its proposed Demonstration Project D, but later determined that that substation area by itself had insufficient DERs to meet the high penetration requirement; accordingly SCE expanded its proposal to include the adjacent Camden substation. (SCE June 17, 2016 Comments at 17-18.)

SCE further describes its proposal:

Demonstration D would consist of telecommunication and control systems equipment to forecast, monitor and control high
penetration of DERs. The deployed system would demonstrate how to properly operate multiple DERs in concert. For this demonstration SCE expects to have a mix of customer, utility and third-Party owned DERs. (Idd. at 18.)

SCE’s proposal also utilizes its existing Integrated Grid Project (IGP) that is funded through the Electric Program Investment Charge (EPIC). As a result, SCE’s proposed Demonstration Project D has low incremental non-procurement costs:

As noted in the response to Question No. 7, all SCE activities and implementation costs unrelated to third-party DER procurement (i.e., all SCE capital expenditures and O&M [Operations and Maintenance] expenses) will be executed as part of the IGP, and therefore will leverage the existing IGP funding from the EPIC program. Thus, SCE currently anticipates zero incremental funding required for SCE capital expenditures and O&M costs. (SCE June 17, 2016 Comments at 30.)

Other parties expressed some concern about the details of SCE’s proposed Demonstration Project D, such as GPI’s concern that SCE’s use of existing demonstration projects and pilots within its Demonstration D area and the corresponding “fractured nature” of the funding may somehow inhibit SCE’s ability to manage or get useful information from the multiple DERs. (GPI July 22, 2016 Comments at 17.) But otherwise, there is no significant opposition to SCE’s proposed Demonstration Project D.

Given its low incremental cost from its use of existing resources and its general consistency with the Commission’s guidance, SCE’s proposed Demonstration Project D (and proposed schedule) is approved. SCE is instructed to utilize EPIC funding to meet the non-procurement expenses; this Demonstration Project should have zero procurement costs.
3.2.3. SDG&E

SDG&E’s proposed Demonstration Project D would be located at its Valley Center substation, which currently has a significant amount of DERs; in addition, SDG&E notes that it is in a rural location, which would allow for acquisition of land for additional DER equipment and facilities. (SDG&E June 17, 2016 Response, Attachment 1.)

ORA points out, however, that SDG&E apparently would need to procure significant additional DERs in the area in order to reach a high DER penetration level. (ORA August 26, 2016 Comments at 23.) ORA expressed the additional concern that SDG&E’s plan would essentially create issues (caused by high DER penetration) that would have adverse impacts on customers served by the Valley Center substation, rather than using DER as a solution. (Id.)

TURN argues that SDG&E should not do Request for Offers (RFO) for its proposed Demonstration Project D, and that it could instead leverage Demonstration Project C and other already-funded projects. (TURN August 26, 2016 Comments at 6-8.) GPI similarly questions how SDG&E’s proposed Demonstration Project D differs from its proposed Demonstration Project C. (GPI July 22, 2016 Comments at 17.)

As presented, SDG&E’s proposed Demonstration Project D is not approved. SDG&E is directed to work with the staff of the Commission’s Energy Division to determine if the goals and objectives of Demonstration Project D could be addressed and accomplished through Demonstration Projects C and E.4

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4 Demonstration Project E is for a microgrid, which will tend to have a high DER penetration level.
3.3. Demonstration Project E

The Scoping Memo for this proceeding described Demonstration Project E as follows:

Demonstrate a microgrid where DERs (both customer-owned and utility-owned) serve a significant portion of customer load and reliability services. This project will demonstrate the use of a DER management system for controlling the resources. The project will develop, document, and implement a methodology for construction and operation/dispatch of the DER portfolio. The project will include both third-party-owned and utility-owned resources. (Scoping Memo at 8-9.)

3.3.1. PG&E

PG&E has proposed to use Angel Island as the location for its Demonstration Project E. Angel Island is an island in San Francisco Bay; in the past it received its bulk electric service via two 12 kV submarine cables, served from the Alto 1123 circuit, but one of the cables sustained unrecoverable damage and is no longer in service. (PG&E June 17, 2016 Revised Proposal at A-21.)

PG&E proposes to install a mix of wind and photovoltaic solar generation, combined with battery energy storage, demand response and energy efficiency, and propane generators for backup. (Id. at A-23-24.) PG&E states that it will own, operate, and maintain all of the equipment on Angel Island for Demonstration Project E. (Id. at A-24.)

ORA raises some concerns with PG&E’s proposed Demonstration Project E. First, ORA notes that:

PG&E does not describe how the infrastructure on Angel Island, the DER sites, and load profiles are consistent with other probable microgrid locations, so it is not possible to determine the replicability of this project. (ORA July 22, 2016 Comments at 40.)
In addition, ORA argues that this Demonstration Project may be unnecessary, as it duplicates a pre-existing microgrid project:

The issue of duplication of demonstration projects appears again for this project as PG&E is already a partner in a [California Energy Commission] CEC EPIC funded microgrid titled “Demonstrating a Community Microgrid at the Blue Lake Rancheria.”  (Id.)

According to ORA, the goals of the Blue Lake Rancheria microgrid are consistent with the Commission’s guidance for Demonstration Project E.  (Id.)

TURN also raises the duplication issue:  “Specifically, PG&E proposes building a micro-grid on Angel Island, even though it has an existing microgrid at Santa Rita jail.”  (TURN July 22, 2016 Comments at 8.)  According to TURN, PG&E has not explained why it cannot use an existing microgrid project for Demonstration Project E.  (Id.)

PG&E disagrees with ORA and TURN on the duplication issue, but PG&E’s Reply Comments did not really address their arguments or explain why its proposal here is not duplicative of one or more existing PG&E microgrid projects.  (PG&E July 29, 2016 Reply Comments at 2.)  At hearings, PG&E’s witness did provide some testimony in response to the arguments of ORA and TURN, but it was not particularly detailed, and did not fully address the issues raised by ORA and TURN.  (Transcript v. 1 at 25-30.)

The Scoping Memo in this proceeding called for Demonstration Project E to include both customer-owned (or third-party-owned) and utility-owned resources.  (Scoping Memo at 8-9.)  But PG&E states that it will own, operate, and maintain all of the equipment for Demonstration Project E.  (PG&E June 17, 2016 Revised Proposal at A-24.)  This is inconsistent with the direction of the Scoping Memo.
In addition, Marin Clean Energy submitted confidential material that raises additional concerns about the value of PG&E’s Demonstration Project, and whether it would provide useful information for broader deployment of DERs. (Marin Clean Energy July 22, 2016 Comments at 3.)

Based on the facts presented and the goals of this proceeding, PG&E’s proposed Demonstration Project E is not approved. If PG&E believes that an existing microgrid project can be used to satisfy the objectives of Demonstration Project E, PG&E may file and serve Comments within 45 days of the date of this decision requesting approval for a new Demonstration Project E, including a description of any modifications needed to the existing facilities. Parties may file and serve Reply Comments no later than 30 days from the date of service of PG&E’s Comments proposing a new Demonstration Project E.

3.3.2. SCE

For its Demonstration Project E, SCE has proposed to deploy an inverter-only microgrid in a residential area adjacent to the University California, Irvine. (SCE June 17, 2016 Comments at 34; SCE July 29, 2016 Comments at 4.) SCE’s arguments in support of its proposal include:

The proposed location includes the area that hosted the Irvine Smart Grid Demonstration (ISGD) project, which was one of thirty two Department of Energy Regional Smart Grid Demonstrations funded through the American Recovery and Reinvestment Act. The Irvine location is attractive for several reasons, including:

- Equipment installed and integrated during the ISGD project can be leveraged to accelerate the Project E schedule. Leveraging this equipment reduces cost and reduces schedule risk. […]
- An existing array of resources (PV, storage) can be used for the demonstration, reducing cost.
- Initial engagement shows hosting customer willingness to provide physical locations where SCE DER resources and control
systems may be located. [...] Therefore this location is likely to reduce cost and mitigate schedule risk. (SCE June 17, 2016 Comments at 38.)

SCE’s proposed budget for its Demonstration Project E is $10.2 million, excluding procurement costs. (SCE June 22, 2016 Comments at 12-14.) This is significantly higher than the comparable cost estimates of PG&E ($4.2 million) and SDG&E ($500,000) for their Demonstration Project E proposals. The existing equipment only includes a small portion of the needed generation, and does not include other necessary equipment, so it is not clear that SCE has in fact gained significant cost savings from its choice of location.

In addition to its cost, the nature, location and duration of SCE’s proposed Demonstration Project E also raised concerns. ORA identified a number of potential problems with SCE’s proposal:

One of the unique weaknesses of this project is that it does not appear to be located such that it serves a particular reliability need. A potential benefit of microgrids is added reliability and resiliency, and this assumes customers on the microgrid receive benefits that offset the additional costs of the microgrid. Nothing in SCE’s proposal indicates that the 151 residential customers and one community center require more reliability or resiliency than SCE provides to its customers generally. The fact that SCE includes $850,000 for “maintenance and decommissioning” further suggests that the microgrid is not needed and that SCE does not intend to operate the system beyond this project. It does not appear that this location is representative of where microgrids would likely be deployed. (ORA July 22, 2016 Comments at 42.)

GPI similarly argues that SCE “misses the mark” with its Demonstration Project E proposal:

SCE’s Demonstration E project, which includes dismantling their microgrid, is planned for a location where a microgrid is unnecessary, will not provide any long-term insights into DER
deployment and operation, and provides no lasting benefits to ratepayers. Given these and the following comments on Demonstration E, the GPI recommends rejecting SCE’s Demonstration E project as currently proposed. (GPI July 22, 2016 Comments at 24.)

These criticisms of SCE’s proposed Demonstration Project E are valid; accordingly, SCE’s proposed Demonstration Project E is not approved. If SCE believes that an existing microgrid project can be used to satisfy the objectives of Demonstration Project E, SCE may file and serve Comments within 45 days of the date of this decision requesting approval for a new Demonstration Project E, including a description of any modifications needed to the existing facilities. Parties may file and serve Reply Comments no later than 30 days from the date of service of SCE’s Comments proposing a new Demonstration Project E.

3.3.3. SDG&E

For its Demonstration Project E, SDG&E has proposed to use an existing microgrid at its Borrego Substation, serving customers in Borrego Springs. (SDG&E June 17, 2016 Responses, Attachment A.) Because SDG&E is using an existing microgrid, its incremental costs for Demonstration Project E are $500,000.5

Other parties either support SDG&E’s proposed Demonstration Project E or do not oppose it. (See, e.g., GPI July 22, 2016 Comments at 2.) Parties that addressed SDG&E’s proposed Demonstration Project E generally indicated that they believe it is consistent with the Commission’s guidance for Demonstration

5 SDG&E estimates a total of $14.7 million direct capital and DER procurement costs, with $14.2 million associated with existing and already funded capital projects and $500,000 in incremental unfunded costs. (SDG&E July 22, 2016 Comments, Attachment A at 3.)
Project E. (See, e.g., TURN July 22, 2016 Comments at 9; ORA July 22, 2016 Comments at 38.) We agree, and also appreciate its low incremental cost to ratepayers. SDG&E’s proposed Demonstration Project E is approved. Given that SDG&E is utilizing an existing microgrid, it will be possible to promptly obtain information from this project; accordingly, the schedule in Appendix A also applies to SDG&E’s Demonstration Project E.

3.4. Other Proposals

The Center for Sustainable Energy (CSE) also proposed a demonstration project. CSE’s proposal is for integrating community and grid planning, and is designed to demonstrate how local governments and utilities could work together “to perform data-driven integrated DER planning in San Francisco…” (Ex. DRP2 – CSE1, Attachment at 1; see also July 21, 2016 Comments of CSE.)

Specifically, CSE proposes to facilitate data sharing and collaboration between PG&E and the City and County of San Francisco, and has requested federal Department of Energy (DOE) funding for its proposal. CSE’s proposal does not include any DER deployment or procurement. (Transcript, v. 1, at 106-107.) The total cost of the CSE proposal is $389,551, and CSE has requested $350,551 from DOE. As of the date of evidentiary hearings, DOE had not approved CSE’s request for funding. (Transcript at 106.)

CSE is requesting funding for their proposed demonstration project by adding it to PG&E’s request for rate recovery. In other words, however PG&E gets rate recovery for its demonstration projects, CSE asks that the cost of CSE’s demonstration project be added to that, and PG&E would then pay CSE. (Id. At 108-112.) If CSE receives funding from DOE, the amount paid by PG&E ratepayers would be $39,000, the difference between the cost of CSE’s proposal ($389,551) and the amount requested from DOE ($350,551). If CSE does not get
funding from DOE, CSE is requesting that the total cost of its proposal ($389,551) be recovered from PG&E ratepayers.  (Transcript at 110.)

While PG&E supported CSE’s request for DOE funding (July 21 Comments of CSE, Attachment A), PG&E appeared to be surprised by CSE’s request to recover its costs from PG&E ratepayers.  (Transcript at 110-112.)  In fact, CSE appears to have first mentioned this approach for obtaining funding from PG&E ratepayers in its July 21 Comments.  (Transcript at 110-111.)

The CAISO supports CSE’s proposal, and enumerates possible benefits that the CAISO believes could be achieved from CSE’s proposed demonstration project.  (CAISO July 22 Comments at 1-5.)  While the CSE proposal appears to be well-intentioned, it is not clear from the record of this proceeding that the CSE proposal will actually provide the specific benefits hoped for by the CAISO.  Nor is it clear that PG&E or the other utilities cannot adequately collaborate and share data with local governments, or that CSE’s proposal adds anything to the existing capabilities of the utilities or local governments (such as San Francisco, which is the subject of CSE’s proposal).

We encourage the utilities to work with local governments to provide the potential benefits identified by the California Independent System Operator (CAISO), and support the utilities’ working with CSE if it obtains DOE funding.  Nevertheless, CSE has not provided an adequate basis to support rate recovery from PG&E’s ratepayers.  Accordingly, we deny CSE’s request for ratepayer funding of its demonstration project.

Bloom Energy proposed that Demonstration Project C should include projects that: “[D]emonstrate the benefits of a Bloom solid-oxide fuel cell placed in service on the IOU distribution system.”  (Bloom Energy June 17, 2016 Comments.)  We are not requiring the utilization of any specific vendor’s
technology for Demonstration Project C. The utilities or third parties may utilize Bloom Energy (or other) fuel cells if they choose to, but are not required to do so. Bloom Energy’s proposed demonstration project is not approved.

3.5. Process for Approval

Parties have made a range of suggestions for the solicitation process to be used in procuring DERs for the Demonstration Projects approved by this decision. SDG&E and ORA recommend the use of the Competitive Solicitation Framework (CSF) being addressed in the Commission’s Integration of Distributed Energy Resources (IDER) proceeding, R.14-10-003. (SDG&E August 26, 2016 Comments at 2-3; ORA July 22, 2016 Comments at 5-6.)

The IDER pilot schedule incorporates an approval process taking 17 months before any additional DER projects commence construction. The IDER process, however, is designed to address a more initiatory situation than is present in this proceeding; here the Demonstration Projects and their locations have largely already been determined. Accordingly, it does not make sense to apply the full IDER schedule here, particularly given our interest in obtaining early results from the Demonstration Projects. For Demonstration Project C and SDG&E’s Demonstration Project E we will use the schedule set forth in Appendix A, as discussed above, rather than the IDER schedule.

It does, however, make sense to adopt the relevant components of the CSF approved in the IDER proceeding for the purposes of Demonstration Project DER solicitations. Accordingly, we require all DER solicitations issued to utilize the grid services definitions and valuation components (Evaluation Methodology) set forth in the IDER Decision (D.) 16-12-036.

The IDER Decision on CSF and Regulatory Incentives addresses energy efficiency incrementality issues by having each utility propose and finalize a
counting method from the five methods that came out of the CSF Working Group Final Report. (D.16-12-036 at 18-22.) For the purposes of the Demonstration Projects here, we direct the utilities to utilize the same methods they will use for the IDER Incentives Pilot. The Incentives Pilot’s intent is to “mirror” Demonstration Project C; therefore, it makes sense to utilize the same methods here as outlined in the IDER decision.

Furthermore, we adopt ten out of the 12 solicitation principles listed in the IDER Decision. These are:

- Principle 1: Framework meets the identified need on a least cost, best fit basis;
- Principle 2: Framework utilizes a competitive process with broad markets;
- Principle 3: Framework is technology neutral;
- Principle 4: Framework is transparent as allowed within confidentiality boundaries;
- Principle 5: Framework identifies a need without prejudging the technology;
- Principle 6: Framework does not limit the amount of any one type of technology;
- Principle 8: Framework is a fair and consistent process;
- Principle 9: Framework focuses on the identified need;
- Principle 10: Framework provides sufficient assurance of performance; and
- Principle 11: Framework allows for flexibility in the number and type of bids; and

Solicitation Principles 7 (Framework is a streamlined process) and 12 (Framework includes a lessons learned feedback loop) are specific to the more extensive IDER process and are not readily applicable to the DRP Demonstration Project solicitations.
The utilities must demonstrate adherence to these 10 principles in their requests for contract approval. With regards to solicitation outreach, the utilities shall continue existing market outreach practices but should keep in mind the two-month window in the schedule in Appendix A, which is applicable to Demonstration Project C and SDG&E’s Demonstration Project E.

ORA recommends that the Commission adopt a cap on procurement costs. (ORA July 22, 2016 Comments at 4; ORA August 26, 2016 Comments at 3-9.) ORA recommends a “soft” cap, which includes both non-procurement costs (as filed by the utilities) and procurement costs, that could be increased by the filing of a Tier 3 advice letter. (ORA August 26, 2016 Comments at 5-6.) Given that the actual DER procurement costs (and their corresponding rate impacts), are currently unknown, this seems to be a reasonable precaution to take in order to protect ratepayers from potentially high costs. ORA’s cap is based on a formula, and the level of the cap would be confidential to further protect ratepayers. We adopt ORA’s cost cap proposal.

As discussed above, the non-procurement costs for SCE’s Demonstration Project C have been reduced to $3 million (from SCE’s original proposal of $9.3 million); the ORA-recommended cost cap is therefore reduced by a corresponding amount.

For SDG&E’s Demonstration Project C, ORA stated: “Unlike the other utilities, SDG&E declined to provide ORA with information regarding any traditional wire solutions which could be deferred by its proposed Demo C project…” (ORA August 26, 2016 Comments at 16.) As a result, ORA could not calculate a cost cap for SDG&E’s Demonstration Project C. Because of this, ORA: “[R]ecommends that the Commission require SDG&E to provide cost
information on the deferral value of its proposed Demo C Project so a reasonable budget cap can be established for this project.” (Id. at 16-17.)

We agree with ORA’s recommendation. SDG&E is directed to work with the Commission’s Energy Division to develop a cost cap for its Demonstration Project C, using the same method used by ORA for the other cost caps (taking into consideration that we have already removed $4.6 million from SDG&E’s non-DER procurement budget). SDG&E will submit a Tier 2 Advice Letter within 45 days of approval of this decision to set the soft cost cap and justify the costs associated with the proposed DER procurement.

We also adopt ORA’s proposal for the utilities to file a Tier 3 Advice Letter to increase the cost cap.

ORA recommends that the results of solicitations be reviewed and approved by application, rather than advice letter, in large part due to uncertainties around the solicitation process. (ORA August 26, 2016 at 9-10.) Given the steps we have taken above (the adoption of certain elements of the IDER CSF and the cost cap), this appears to be unnecessary. Accordingly, the utilities may submit their requests for the approval of contracts coming from the solicitations via Tier 3 Advice Letter.6 The Tier 3 Advice Letters to approve the contracts shall explain the utilities’ solicitation process and include contract information. Stakeholder input with respect to solicitations will focus on how bids were evaluated and selected, and will come through protests and responses to the Tier 3 Advice Letters. The Advice Letter should also state the reasons new DER is needed—the utilities should provide a comprehensive list of existing

6 SDG&E must submit its Tier 2 Advice Letter to set the cost cap for its Demonstration Project C prior to submitting an Advice Letter for contract approval for Demonstration Project C.
DER within the demonstration projects, identify them as third-party or utility-owned, justify why new DER is needed and how existing DER is not capable of meeting project goals and objectives, and state the value of any deferred investments.\(^7\)

Several parties (e.g., Solar City, Clean Coalition, Vote Solar, TURN, ORA) argue that the utilities should leverage existing DER or existing RD&D projects before procuring new DER. We agree. The utilities should leverage use of existing third-party systems to manage DER resources, and should utilize capabilities of existing DER before procuring new DER for the demonstration projects.

As Clean Coalition argued, the process should make “[I]mmediate initial use of utility owned facilities and existing third party facilities in demonstration project design, followed by incremental addition of additional third party facilities.” (Clean Coalition July 22, 2016 Comments at 6.) Similarly, Vote Solar is correct that the: “[D]emonstration projects provide an ideal environment to evaluate if third-party dispatched resources can provide reliable, consistent response to utility signals, and if reliance on third-party controlled DER and third-party owned communications infrastructure is more cost effective.” (Vote Solar August 26, 2016 Comments at 4.)

The utilities should provide a clear basis for any reliance on utility-owned assets, and accordingly the utilities are directed to do a side-by-side comparison of the costs and cost-effectiveness of third-party and utility-controlled DER alternatives, and should also explain how the DER portfolio was chosen. This

\(^7\) To the extent this information is confidential, the utility may include it in a confidential attachment.
information is not required to be provided in the Advice Letters seeking contract approval, but will be required to be provided in the reports to be submitted to the Commission, as described in Appendix A.

The utilities have proposed several metrics to assess Demonstration Project performance; several of these metrics overlap across multiple projects, while others are project-specific. While the metrics proposed by PG&E and SDG&E are relevant, SCE’s proposed metrics are a good starting point to assess project performance. To ensure consistent evaluation of the projects across the utilities, the tables in Appendix B summarize the metrics to be used to assess project performance for each of the demonstration projects.

SCE and PG&E proposed ratemaking treatments for the costs to implement the Demonstration Projects.

SCE proposed that this decision should approve the budget and authorize cost recovery for SCE’s O&M expenses and capital expenditures, direct SCE to file a Tier 2 advice letter to open a DRP Demonstration Balancing Account to record the revenue requirement associated with the demonstration project, and direct SCE to file an annual Tier 3 Advice Letter to recover the prior year’s under-collected balance. For approval of contracts for third-party DER resources, SCE would conduct an RFO and submit a Tier 3 Advice Letter seeking approval for each contract. (SCE June 17, 2016 Comments at 13-14.)

PG&E described its ratemaking proposal:

For recovery of the incremental costs associated with its DRP Demonstration Program, PG&E requests that the Commission authorize PG&E to include in electric distribution rates the forecast revenue requirements associated with the demonstration projects described below beginning January 1, 2017. PG&E requests that the Commission authorize PG&E to establish the Distribution Resources Plan Demonstration Program Balancing
Account (DRPDPA), which is a one-way balancing account, to record and track the authorized revenue requirements compared to the revenue requirements associated with actual costs, including expense and capital. Upon conclusion of the Projects, any unspent funding in the tracking account would be returned to customers by transferring the balance to the Distribution Revenue Adjustment Mechanism (DRAM) as part of PG&E’s Annual Electric True-up (AET) process. (PG&E June 17, 2016 Comments at A-1 – A-2.)

These proposals are mostly similar, although we prefer PG&E’s proposed one-way balancing account. SCE’s name (and corresponding acronym) for the balancing account is slightly shorter, so we will adopt that name (DRP Demonstration Balancing Account) rather than PG&E’s. Otherwise, we approve PG&E’s proposed process for all three utilities. Utilities may only record incremental procurement- and non-procurement-related O&M expenses and capital expenditures in the DRP Demonstration Balancing Account, and not overheads or Administrative and General expenses that would otherwise be approved in a General Rate Case.

4. Categorization and Need for Hearing

Track 2 of these consolidated proceedings is categorized as ratesetting. The Scoping Memo determined that hearings may be needed; hearings were requested by ORA, and were held on August 10 and 11, 2016.

5. Comments on Proposed Decision

The proposed decision of ALJ Allen in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission’s Rules of Practice and Procedure. Comments were filed on _______, and reply comments were filed on _______ by _______.

- 27 -
6. **Assignment of Proceeding**

Commission President Michael Picker is the assigned Commissioner and Peter V. Allen and Robert III Mason are the assigned Administrative Law Judges in this proceeding.

**Findings of Fact**

1. PG&E’s Demonstration Project C is in a reasonable location and has reasonable costs.
2. SCE’s Demonstration Project C is in a reasonable location.
3. SCE’s proposed budget for its Demonstration Project C is significantly too high.
4. SDG&E’s Demonstration Project C is in a reasonable location.
5. SDG&E’s proposed use of $4.6 million for utility-owned energy storage as part of its Demonstration Project C is not appropriate.
6. The utilities’ proposed schedules for Demonstration Project C are too slow, and would unnecessarily delay the availability of information from Demonstration Project C.
7. PG&E’s Demonstration Project D is generally consistent with the Commission’s guidance and has reasonable costs.
8. SCE’s Demonstration Project D is generally consistent with the Commission’s guidance and has reasonable costs.
9. SDG&E’s Demonstration Project D, as proposed, does not provide adequate net benefits.
10. PG&E’s Demonstration Project E is not consistent with the Commission’s guidance, and presents other potential problems.
11. SCE’s Demonstration Project E does not provide adequate net benefits.
12. SDG&E’s Demonstration Project E is in a reasonable location and has reasonable costs.

13. The Center for Sustainable Energy’s proposed demonstration project does not provide adequate net benefits.

14. Bloom Energy’s proposed demonstration project is not consistent with the Commission’s guidance.

15. The Commission recently adopted D.16-12-036 in the IDER proceeding, aspects of which are applicable to the subject of this proceeding.

16. A cost cap including both procurement and non-procurement costs would help ensure that the costs of the Demonstration Projects are reasonable.

17. Utilities should obtain Commission approval for their procurement of Demonstration Project contracts.

18. The Demonstration Projects are intended to provide information that can be used in the deployment of DER.

19. Information about the Demonstration Projects should be comparable across utilities.

20. The reasonable costs of the Demonstration Projects are recoverable in utility rates.

Conclusions of Law

1. PG&E’s Demonstration Project C should be approved.

2. SCE’s Demonstration Project C should be approved, but with a significantly reduced budget.

3. SDG&E’s Demonstration Project C should be approved, but with the removal of the proposed $4.6 million of utility-owned energy storage.

4. Demonstration Project C should be implemented on an accelerated schedule.
5. PG&E’s Demonstration Project D should be approved.
6. SCE’s Demonstration Project D should be approved.
7. SDG&E’s Demonstration Project D should not be approved.
8. PG&E’s Demonstration Project E should not be approved.
9. SCE’s Demonstration Project E should not be approved.
10. SDG&E’s Demonstration Project E should be approved.
11. The Center for Sustainable Energy’s proposed demonstration project should not be approved.
12. Bloom Energy’s proposed demonstration project should not be approved.
13. Applicable provisions of D.16-12-036 should be used here.
14. A cost cap including both procurement and non-procurement costs should be adopted for the Demonstration Projects.
15. Utilities should be required to submit their requests for approval of Demonstration Project contracts via Tier 3 Advice Letters.
16. Reports to the Commission regarding the Demonstration Projects should be required.
17. Common metrics should be applied to the Demonstration Projects.
18. Rate recovery for the reasonable costs of the Demonstration Projects should be approved.

**ORDER**

**IT IS ORDERED** that:
1. Pacific Gas and Electric Company’s Demonstration Project C is approved.
2. Southern California Edison Company’s Demonstration Project C is approved with a total non-procurement budget of $3 million.
3. San Diego Gas & Electric Company’s Demonstration Project C is approved with the removal of utility-owned storage and a corresponding budget reduction of $4.6 million.

4. The schedule for implementation of Demonstration Project C is set forth in Appendix A to this decision.


7. San Diego Gas & Electric Company’s Demonstration Project D is not approved.

8. San Diego Gas & Electric Company is directed to work with the staff of the Commission’s Energy Division to determine if the goals and objectives of Demonstration Project D could be addressed and accomplished through Demonstration Projects C and E.

9. Pacific Gas and Electric Company’s Demonstration Project E is not approved.

10. Pacific Gas and Electric Company may file and serve Comments within 45 days of the date of this decision requesting approval for a new Demonstration Project E using an existing microgrid project. Other parties may file and serve Reply Comments no later than 30 days from service of the Comments proposing a new Demonstration Project E.

11. Southern California Edison Company’s Demonstration Project E is not approved.
12. Southern California Edison Company may file and serve Comments within 45 days of the date of this decision requesting approval for a new Demonstration Project E using an existing microgrid project. Other parties may file and serve Reply Comments no later than 30 days from service of the Comments proposing a new Demonstration Project E.

13. San Diego Gas & Electric Company’s Demonstration Project E is approved.

14. The schedule for implementation of San Diego Gas & Electric Company’s Demonstration Project E is set forth in Appendix A to this decision.

15. The Center for Sustainable Energy’s request for ratepayer funding of its proposed demonstration project is not approved.

16. Bloom Energy’s proposed demonstration project is not approved.

17. All utilities should use applicable provisions of Integrated Distributed Energy Resources Decision 16-12-036, particularly the grid services definitions, valuation components, and counting methods.

18. The recommendation of the Office of Ratepayer Advocates for the adoption of a soft cost cap including both procurement and non-procurement costs is adopted.

19. An increase in the level of the cost cap can be requested by filing a Tier 3 advice letter

20. San Diego Gas & Electric Company is directed to work with the Commission’s Energy Division to develop a cost cap for its Demonstration Project C.

21. San Diego Gas & Electric Company will submit a Tier 2 Advice Letter within 45 days of approval of this decision to set the cost cap for its Demonstration Project C.
22. The utilities must submit their requests for the approval of Demonstration Project contracts via Tier 3 Advice Letter.

23. The utilities are required to file reports on the status of their Demonstration Projects as set forth in Appendix A.

24. All reports and compliance filings ordered by this decision shall be submitted to Energy Division’s Central Files as well as served via email on the service list of this proceeding. The utilities shall follow the current guidance from the Energy Division about submitting documents to Energy Division’s Central Files. Energy Division’s Central Files may be contacted by email at energydivisioncentralfiles@cpuc.ca.gov.

25. The metrics to be used to assess Demonstration Project performance are set forth in Appendix B to this decision.

26. The utilities are authorized to establish a one-way “DRP Demonstration Balancing Account” to record and track the authorized revenue requirements compared to the revenue requirements associated with actual costs, including expense and capital. Unspent funding in the account will be returned to customers by transferring the balance to the Distribution Revenue Adjustment Mechanism.

27. The utilities may only record incremental procurement- and non-procurement-related Operations and Maintenance expenses and capital expenditures in the Distribution Resources Plan Demonstration Balancing Account, and not overheads or Administrative and General expenses that would otherwise be approved in a General Rate Case.

This order is effective today.

Dated ________________________, at San Francisco, California.
APPENDIX A

Reporting Requirements and Schedule for Demonstration Project C and E.

ReportsStaff distinguishes between: (1) reports that inform the Commission on the status of the projects, such as if there are delays in implementing the projects or status of construction (Project Status Reports); and (2) reports that analyze data of DER performance once the project commences (Project Data Reports).

The schedule below only lists when the Project Data Reports are due. This reporting schedule for the Project Data Reports will apply to Demonstration Projects C and E.

The reporting format shall be as follows:

**Project Status Reports**

The utilities are required to file information-only reports, after approval of the contracts, updating the Commission on the progress of the project deployment and any obstacles that may delay the start of data gathering. The first report should be 3 months after approval of the contracts, and 3 months apart thereafter and lasting until completion of construction and notifying the commission when data gathering will start. The utilities are instructed to work with Energy Division on the content of these reports, but at a minimum they should contain the status of the project, relevant changes or modifications to the schedule and updating any milestones, challenges encountered, and solutions posed. The utilities shall also explain how the DER portfolio was chosen.
Project Data Reports

The data gathering phase of the projects will contain three reports, as outlined in the schedule. These reports shall be filed as Information-Only filings. The reports are divided such that the first report will analyze the first three months of data, the second report the following six months, and the last report the last 3 months of data gathering along with a cumulative report on the entire year. In general, the utilities have 2 months to analyze the data and file the report. The utilities should provide a clear basis for any reliance on utility-owned assets, and accordingly the utilities are directed to do a side-by-side comparison of the costs and cost-effectiveness of third-party and utility-controlled DER alternatives. The reports should also include any challengers and changes in circumstances that delayed data gathering/analysis and solutions taken.

The following table outlines the schedule for Demonstration Project C and SDG&E’s Demonstration Project E.
<table>
<thead>
<tr>
<th>Month</th>
<th>Action</th>
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<tbody>
<tr>
<td></td>
<td>(Need for new DER is determined)</td>
<td>(No need for new DER)</td>
</tr>
<tr>
<td>1</td>
<td>Commence Project &amp; Identify need for New DER</td>
<td>Commence Project &amp; Identify need for New DER</td>
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<tr>
<td>2</td>
<td>Procure new DER if needed and file Tier 3 Advice Letters for approval of contracts</td>
<td>Testing of Operations</td>
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<td>3</td>
<td>CPUC Approval (2 months max)</td>
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<tr>
<td>4</td>
<td>Construction of new DER</td>
<td>1st Progress Report Filed (Months 5, 6, 7)</td>
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<td>5</td>
<td>Testing of Operations</td>
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<td>6</td>
<td>Projects Commence (Data Gathering)</td>
<td>Data Gathering Ends &amp; 2nd Progress Report (Months 8 through 13)</td>
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<td>10</td>
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<td>3rd (Months 14 through 16) and Cumulative Progress Report</td>
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<td>1st Progress Report Filed (Months 16, 17, 18)</td>
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<tr>
<td>30</td>
<td>3rd (Months 25 through 27) and Cumulative Progress Report</td>
<td></td>
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</table>

(End of Appendix A)
APPENDIX B

To ensure consistent evaluation of the projects across the utilities, the following tables summarize the metrics to be used to assess project performance for each of the demonstration projects.

**Metrics for Demonstration Projects C and D**

<table>
<thead>
<tr>
<th>Performance Measure</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>DER Capacity Output</td>
<td>Measure the DER capacity output for one year or greater, to compare to the forecasted output prior to procurement</td>
</tr>
<tr>
<td>DER Energy Output</td>
<td>Measure the DER energy output for one year or greater, to compared to forecasted energy output prior to procurement</td>
</tr>
<tr>
<td>Local Utility System Voltage</td>
<td>Measure the utility system voltage for one year or greater, at a point in proximity to the DER installation and compare to a year prior to DER installation</td>
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<tr>
<td>Utility Circuit Load</td>
<td>Measure the utility circuit load for the circuit which hosts the DER, for one year or greater, and compare to a year prior to DER installation</td>
</tr>
<tr>
<td>Utility Circuit Energy</td>
<td>Measure the utility circuit energy delivery for the circuit which hosts the DER, for one year or greater, and compare to a year prior to DER installation</td>
</tr>
<tr>
<td>Utility to DER Dispatch Request</td>
<td>Measure the ability of the DER to respond to utility requests when called upon to provide distribution services and solve a local grid/system need.</td>
</tr>
<tr>
<td>Utility system energy mix</td>
<td>Measure the utility’s energy delivery mix, such that appropriate GHG emission offsets can be evaluated and compared with the DER, while the DER is in service</td>
</tr>
<tr>
<td>DER Project capacity factor</td>
<td>Measure the ratio of the actual output power to its full nameplate capacity over a period of time (usually one year).</td>
</tr>
<tr>
<td>DER Project Capacity cost</td>
<td>Unitize the actual cost of a DER to provide capacity per unit of time.</td>
</tr>
<tr>
<td>DER Project Energy cost</td>
<td>Unitize the actual cost of a DER to provide energy per unit of time.</td>
</tr>
<tr>
<td>DER Reactive Power Output</td>
<td>Measure the DER reactive power output for one year or greater, to study the ability of the resource to supply reactive power</td>
</tr>
<tr>
<td>Distribution Capacity and Hosting Capacity Service Effectiveness</td>
<td>Measure the technical effectiveness of DER dispatch with mitigating projected equipment overloads. Comparative analysis will be performed evaluating projected equipment loading levels against actual equipment loading levels and conditions when sourced DER</td>
</tr>
</tbody>
</table>
DER Readiness & Assurance | Measuring the time between contract award to operation to ensure timeliness in meeting the locational needs. Measuring the communication reliability between PG&E dispatch operators and the aggregator owned DER equipment. Ensure that DER readiness is available when expected to contribute to the grid needs and utility reserved periods pending contract arrangements.

Process Evaluation | A process evaluation study performed by a third party expert to be made public describing the end to end process of Project C implementation and suggesting enhancements to the future DER deployments with similar use cases. The process evaluation will critique the end to end process and provide suggestions for improvements in development of least-cost/best-fit DER portfolios and the sourcing of those portfolios. The process evaluation will also estimate the overall cost-effectiveness of the project and make recommendations on how overall cost-effectiveness can be approved in future deployments.

Point of Common Coupling Voltage Support | Measure the voltage increase/decrease seen at the PCC due to the DER operation.

Turn Around Efficiency | Measure the overall energy lost (%) from storage and utilization of energy.

DER Operational Mode Validation | Verify the DER solution modes of operation, such as peak shaving, operate as expected.

### Demonstration C and D: Smart Device/Intelligent Electronic Devices Performance Metrics

<table>
<thead>
<tr>
<th>Performance Measure</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>DER Real Power Output</td>
<td>Measure the real power (kW) output of the DER solution compared to the nameplate rating.</td>
</tr>
<tr>
<td>DER Reactive Power Output</td>
<td>Measure the reactive power (kVAR) output of the DER solution compared to the nameplate rating.</td>
</tr>
<tr>
<td>Communication Latency</td>
<td>Latency between issued command to actual operation will be measured.</td>
</tr>
<tr>
<td>Communication resiliency</td>
<td>Communication failures and signal loss will be measured.</td>
</tr>
<tr>
<td>Point of Common Coupling Voltage Support</td>
<td>Measure the voltage increase/decrease seen at the PCC due to the DER operation.</td>
</tr>
<tr>
<td>Effectiveness of proposed autonomous operations</td>
<td>Proposed autonomous solutions effectiveness such as automated Volt/VAR operations should be compared to simulated results.</td>
</tr>
</tbody>
</table>
### Additional Metrics for Demonstration Project C

<table>
<thead>
<tr>
<th>Performance Measure</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>LNBA Validation</td>
<td>An evaluation, measurement and verification (EM&amp;V) study performed by a third party expert to be made public suggesting enhancements to the LNBA model estimates that address any identified gaps between estimated LNBA and the observed results from Project C.</td>
</tr>
</tbody>
</table>

### Additional Metrics for Demonstration Project D

<table>
<thead>
<tr>
<th>Performance Measure</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>DER Penetration</td>
<td>Measure of the amount of DER generation (power) divided by the peak circuit or area demand expressed as a percentage</td>
</tr>
<tr>
<td>Voltage Controlability</td>
<td>Comparison between the voltage setpoint and local utility system voltage measurement</td>
</tr>
<tr>
<td>Power Flow Controlability</td>
<td>Comparison between the power flow setpoint and utility circuit load measurement</td>
</tr>
<tr>
<td>Control and Data Management</td>
<td>Measure the time it takes to gather, process, make recommendation to operator and execute on a command.</td>
</tr>
</tbody>
</table>

### Metrics for Demonstration Projects E

<table>
<thead>
<tr>
<th>Performance Measure</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Island Reliability</td>
<td>Track transitions to and from island mode and during island mode operation; traditional electric utility metrics of momentary outage frequency, sustained outage frequency and sustained outage duration will be used</td>
</tr>
<tr>
<td>Island Power Quality</td>
<td>Measure and compare total harmonic distortion (THD), voltage sags and swells, through transitions to and from island mode and during island mode operation.</td>
</tr>
<tr>
<td>Island Duration</td>
<td>Measure that the minimum island duration requirement of 2 hours has been met</td>
</tr>
<tr>
<td>DER Capacity Output</td>
<td>Measure and verify how much DER (3rd party and other) power was utilized to meet the island duration requirement</td>
</tr>
<tr>
<td>DER Energy Output</td>
<td>Measure and verify how much DER (3rd party or other) energy was utilized to meet the island duration requirement</td>
</tr>
<tr>
<td>Local Utility System Voltage</td>
<td>Measure the utility system voltage during island mode</td>
</tr>
<tr>
<td>Measure</td>
<td>Description</td>
</tr>
<tr>
<td>----------------------------------------------</td>
<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>Utility Circuit Load</strong></td>
<td>Measure the utility circuit load for the circuit which hosts the DER during island mode operation</td>
</tr>
<tr>
<td><strong>Utility Circuit Energy</strong></td>
<td>Measure the utility circuit energy delivery for the circuit which hosts the DER during island mode operation</td>
</tr>
<tr>
<td><strong>Utility to DER Dispatch Request</strong></td>
<td>Measure the ability of the DER to respond to utility requests when called upon to support the microgrid.</td>
</tr>
<tr>
<td><strong>Island Voltage</strong></td>
<td>Measure the island's voltage during island mode operation</td>
</tr>
<tr>
<td><strong>Customer Feedback</strong></td>
<td>Through surveys and/or interviews customers will rate their experience in participating in the demonstration with respect to making resources available to the microgrid, any inconveniences experienced as a result of microgrid operations, and customer service levels provided by SCE and 3rd parties</td>
</tr>
<tr>
<td><strong>Microgrid Service Effectiveness</strong></td>
<td>Measure the effectiveness of DER dispatch with respect to meeting the microgrid loads</td>
</tr>
<tr>
<td><strong>Microgrid Readiness &amp; Assurance</strong></td>
<td>Measuring the communication reliability between PG&amp;E dedicated microgrid controller and the third-party owned DER equipment. Ensure that DER readiness is available when called upon during emergency services and when meeting real-time load changes. Also, measuring the reliability of protective relaying that will sense an external grid disturbance and island the microgrid</td>
</tr>
<tr>
<td><strong>Process Evaluation</strong></td>
<td>A process evaluation study performed by a third party expert to be made public describing the end to end process of Project E implementation and suggesting enhancements to the future DER deployments with similar use cases. This process evaluation will also critique and provide suggestions for improvements in the process of developing least-cost/best-fit DER portfolios and the sourcing of those portfolios</td>
</tr>
</tbody>
</table>

*(End of Appendix B)*