PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

October 30, 2018

**Advice Letter 5096-E/5096-E-A and 3855-G**

Erik Jacobson
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Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, CA 94177

**SUBJECT**: **Request for approval of distributed energy resource (DER) procurement for the IDER Utility Regulatory Incentive Mechanism Pilot (Incentive Pilot).**

Dear Mr. Jacobson:

Advice Letter 5096-E/5096-E-A and 3855-G are effective as of October 25, 2018 per Resolution # E-4956.

Sincerely,

Edward Randolph

Edward Randolph
Director, Energy Division

**Erik Jacobson**
Director
Regulatory Relations

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June 16, 2017

**Advice 5096-E**
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

**Subject: Request for approval of distributed energy resource (DER) procurement for the IDER Utility Regulatory Incentive Mechanism Pilot (Incentive Pilot)**

## Purpose

Pursuant to Ordering Paragraphs (OPs) 13 and 14 of Decision (D.) 16-12-036, Pacific Gas and Electric Company (PG&E) submits this advice letter requesting the California Public Utilities Commission (Commission or CPUC) approval to procure a distributed energy resource (DER) solution for the IDER Incentive Pilot Candidate Project described below.

## Background

### 1 Regulatory Background

On December 22, 2016, the Commission issued Decision (D.)16-12-036, *Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot,* requiring the participating utilities to implement the Incentive Pilot following the adopted aspects of the Competitive Solicitation Framework. The utilities are required to identify at least one candidate project each, with the option to pursue up to four projects, to test the Framework. The utilities must follow the processes and procedures as described in OP 10 through OP 18 for each project selected.

PG&E has completed the actions required by OPs 10 through OP 13. Specifically, PG&E has completed the following actions required by OP 13:

- PG&E has worked with the Distribution Planning Advisory Group (DPAG) to identify at least one candidate project.
- PG&E's proposed project complements PG&E's Demonstration Project C approved in Rulemaking 14-08-013.

- PG&E has proposed a counting method as described in or as an alternative to the methods in the August 1, 2016 Competitive Solicitation Framework Working Group Report, and with the attributes listed in OP 3, to ensure the DERs procured are incremental to those forecasted.

- PG&E has worked with the DPAG to finalize the counting method as well as a contingency plan for the candidate project.

- PG&E's has selected a project where the solicited DERs have a reasonable chance of being cost-effective consistent with the lists of valuation components approved in OP 5, and has worked with the DPAG to select applicable valuation components.

This Tier three Advice Letter (AL) complies with Step Three of the Incentive Pilot decision requiring PG&E to request Commission approval to procure a DER solution for the candidate project selected pursuant to OP 13.

## 2 IDER Incentive Pilot Candidate Project Identification and Prioritization Process

### 2.1 Distribution Infrastructure Deferral Framework (DIDF)

For the purpose of procuring the DER solution for the candidate project recommended below, PG&E will test the efficacy of a distribution infrastructure deferral framework (DIDF) which includes a more formal process for screening and prioritizing distribution infrastructure projects for potential cost-effective DER solutions. In addition to the more formal process for screening and prioritization of the candidate projects for potential cost-effective DER solutions, the DIDF also includes consultation and input by the DPAG composed of both non-market and market participants as well as an independent professional engineer (IPE) whose role is to advise both the DPAG and PG&E regarding technical aspects related to identification and prioritization of projects for cost-effective DER solutions.

#### 2.1.1 Candidate Project Screening

As discussed in DPAG meetings #2 and #5 (see Appendix B and Appendix E for more details), PG&E employed two screening criteria to develop its initial list of candidate projects. The first screen is a **project timing screen**. The second screen is a **distribution services screen.** The purpose of the **project timing screen** is to ensure that cost-effective DER solutions procured for the IDER Incentive Pilot have sufficient time to fully deploy and began commercial operation prior to the projected need for the distribution services being provided by the DERs. As presented and discussed at DPAG meeting #2, PG&E, SCE and SDG&E all agreed that projects with in-service dates prior to June 2020 would not be potential cost-effective candidate projects for DER solutions under the IDER Incentive Pilot, because the procurement schedule described in D 16

12 036 would not result in fully executed CPUC approved contracts until on or about September/October 2018. DER solutions procured for the Pilot need at least 18 months to 24 months to deploy and begin commercial operations once contracts are effective.

The second screen which was discussed at DPAG meetings #2 and #5 was the **distribution services screen** which consisted of the four distribution services that were listed in the Competitive Solicitations Framework Working Group (CSFWG) final report and endorsed in D 16 12 036. These four services are:

- **Distribution Capacity** services are load-modifying or supply services that distributed energy resources provide via the dispatch of power output for generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure;
- **Voltage Support** services are substation and/or feeder level dynamic voltage management services provided by an individual resource and/or aggregated resources capable of dynamically correcting excursions outside voltage limits as well as supporting conservation voltage reduction strategies in coordination with utility voltage/reactive power control systems;
- **Reliability (Back-Tie)** services are load-modifying or supply service capable of improving local distribution reliability and/or resiliency. Specifically, this service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations; and
- **Resiliency (microgrid)** services are load-modifying or supply services capable of improving local distribution reliability and/or resiliency. This service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations.

As explained by PG&E in DPAG Meeting #5, the application of these two initial DIDF screens resulted in identification of nine potential candidate projects for PG&E's IDER Incentive Pilot.

### 2.1.2 Candidate Project Selection

As explained by PG&E in DPAG Meeting #5, in the second step of the DIDF process PG&E prioritized the nine candidate projects based on two criteria. **The first criterion is for certainty with respect to project timing**. Project timing certainty is an important consideration for IDER Incentive Pilot candidate projects because deferral value is sensitive to the timing of project need. Projects that are driven by individual customer load growth estimates, projects where the estimated circuit or bank deficiency is low relative to the size of the total circuit or bank load or projects where the estimated deficiency is further out on the forecast horizon were given lower priority than projects driven by more general area growth projections, projects with relatively high estimated deficiencies or projects with in-service dates that are more near-term.

**The second prioritization criterion is for feasibility of acquiring the needed DERs in the local market**. This is called the market criterion. The same metrics as described for the project timing certainty criterion were employed for the market criterion. Feasibility of acquiring the needed DERs in the local market is an important criterion because customer adoption of DERs sufficient to mitigate the identified deficiency in the local area in needed to provide the deferral value. Projects that are driven by individual customer load growth estimates, projects where the estimated circuit or bank deficiency is high relative to the size of the total circuit or bank load or projects where the estimated deficiency is near-term were given lower priority than projects driven by more general area growth projections, projects with relatively low estimated deficiencies or projects with in-service dates that allow for a longer deployment period for the DERs.

After applying the prioritization criteria described above, the list of nine candidate projects was reduced to three projects that PG&E believed had sufficient project timing certainty and sufficient market feasibility that DERs could potentially provide a reasonable cost-effective solution. Of those three projects, the Llagas substation project in the San Jose planning area is currently included in our 2016 Energy Storage RFO for distribution deferral and the El Nido substation project in the Chowchilla planning area is currently proposed for DRP demonstration project C. This left the Rincon substation project in the Santa Rosa planning area as PG&E's proposed candidate project for procurement of a cost-effective DER solution in the IDER Incentive Pilot.

#### 2.1.3 DPAG and IPE Review and Comment

The DPAG and IPE reviewed PG&E's application of the DIDF to identify IDER Incentive Pilots and PG&E's prioritization of the candidate projects. The DPAG and IPE questioned the lack of diversity of distribution services among the candidate projects. The distribution service needed in each of PG&E's nine candidate projects was distribution capacity. PG&E explained that projects addressing distribution voltage support are identified, planned and executed on a one or two year ahead time schedule which would not provide sufficient time for a DER solution to be timely solicited and on-line under the competitive solicitation framework schedule outlined in D. 16-12-036. In addition PG&E explained that distribution voltage support projects are generally much less expensive than distribution substation capacity projects and, therefore, selection of distribution voltage support projects may run counter to the Commission's directive (OP 13, D 16 12 036) to select projects where the solicited DERs have a reasonable chance of being cost-effective.

PG&E is open to exploring DER solutions to provide voltage support, but such services would need to be procured under a more streamlined procurement process than the competitive solicitation framework outlined in D 16 12 036.

Similar to projects where the primary distribution service is voltage support, projects where the primary distribution service is reliability provided via a back-tie to an adjacent feeder are currently planned and executed on a one or two year ahead time schedule. In addition, reliability/back-tie projects are generally much less expensive than substation capacity upgrades. PG&E has no proposed projects in its current infrastructure investment plan where the primary distribution service is resiliency provided by a microgrid.

With respect to the nine candidate projects that were identified and prioritized by PG&E, the DPAG and IPE raised no substantive issues, and there appeared to be general understanding and support for the logical process employed (see DPAG meeting #7, IPE Presentations, Appendices H and I). As previously discussed, three of the nine candidate projects were prioritized as feasible for DER alternative mitigation. Two of those projects, Llagas substation project in the San Jose planning area and El Nido substation project in the Chowchilla planning area have already been selected for DER solicitations under the 2016 Energy Storage RFO and DRP Demonstration Project C, respectively, leaving the third project – Rincon substation project in Santa Rosa – as PG&E's proposed location for the IDER Incentive Pilot.

In addition to identification and prioritization of candidate deferral projects, the DPAG and IPE provided the following three general comments and recommendations:

- Desire for transparency around valuation metrics
- Desire for transparency regarding double counting/double payment methodology
- Desire for more opportunities for vendor input during development of solicitation process

The DPAG and IPE recommendations and PG&E's response to those recommendations will be discussed below as part of the specific proposal for the proposed IDER Incentive Pilot location -- Santa Rosa (Rincon Substation).

## 3 Santa Rosa (Rincon Substation) Project Details

A description of the Santa Rosa (Rincon substation) project area as presented at DPAG meeting #5 can be found in Appendix E.

### 3.1 Distribution Service Needed

The local distribution service PG&E will solicit for at the Rincon Substation will be distribution capacity. Based on distribution planning studies between 2MW and 4MW of additional distribution capacity will be needed at the Rincon substation potentially as early as summer 2020[1]. The additional substation capacity will be needed during the months of June through October (inclusive) on both weekdays and weekend between the hours of 3:00 PM to 9:00 PM (inclusive). Dispatchable resources may be called on a day-ahead basis up 6 times a month for not more than 3 consecutive days and for not more than 12 days total during the summer period[2].

Minimum distribution capacity bids considered will be 250 KW to be bid in 250KW increments with maximum bids considered up to 2,000 KW. Behind the meter (BTM) resources must effectively and verifiably reduce distribution system load of retail customers taking service from the Rincon substation during the months and hours described above and in the table below. In front of meter (IFM) resources must effectively and verifiably increase in-area generation during the months and hours described by interconnecting in such a way that they provide the distribution capacity services needed. The additional distribution capacity needs to be available on or before June 2022 and must be maintained at least through end of October 2024. For contingency planning purposes, in order to mitigate project timing uncertainty and to mitigate potential DER delivery uncertainty, PG&E will accept bids in the follow contract term tranches:

- June 2020 through October 2024
- June 2021 through October 2024
- June 2022 through October 2024

| Distribution Services Needed | |
|---|---|
| Type of Service | Distribution Capacity |
| Months | June through October |
| Day Types | Weekdays and Weekends |
| Hours | 3:00 PM to 9:00 PM |
| Number of Calls | Up to 12 Calls per Year |
| Call Notice Time | Day Ahead by 8:00 A.M. |
| Minimum Operation Hours | 3 consecutive hours per day |
| Operating Blocks | 3:00PM-6:00PM; 6:00PM-9:00PM; |

[1] See Section 4 – Contingency Planning – page 14 for more detailed discussion of early phase in of DERs.

[2] PG&E may revise the estimated amount of capacity needed to defer the Rincon substation project based on the results of 2017 distribution planning study updates incorporating observed 2017 summer loading at Rincon substation.

| | |
|---|---|
| Minimum Bid Size | 250 KW |
| Maximum Bid Size | 2,000 KW |
| Minimum Bid Increment | 250 KW |
| Delivery Period | Beginning either June 2020, June 2021 or June 2022 and extending through October 2024 |

**Competitive Solicitation Framework**

**3.2 RFO Schedule**

This Advice Letter represents the first step in the three-part process for granting Utilities' requests to procure a distributed energy resource solution for distribution purposes[3]. Following the filing of the advice letter, the Energy Division is to host a workshop to discuss the contents of the AL, establish a schedule to allow for protests or responses to the AL and issue a proposed resolution for Commission consideration.

Pursuant to the Decision, the Utilities must file Advice Letters within 6 months of the Decision. The Energy Division will determine the exact timing of these processes but should ensure that all steps, including Commission consideration of the Resolution, are completed by no later than 10 months following issuance of the Decision. In addition, the solicitation process is to be completed no later than 14 months from the issuance of the decision.

PG&E's RFO schedule is linked to final approval of the Solicitation Process. To the extent necessary to ensure a successful Pilot and/or successful negotiation and execution of a contract with a DER supplier or suppliers to meet the deferral needs, PG&E reserves the right to request an adjustment to the schedule.

**3.3 Resource Need/Product to be Procured**

Summer Months (June through October)
Hours (Weekdays and Weekends 3:00 PM to 9:00 PM)
250 KW minimum bid / 2,000 KW maximum / 250 KW increments
Dispatchable up to 6 times per month, 12 times per year, 3 consecutive days

Product is distribution capacity service only. Seller is free to operate the resources as it wishes when it is not needed for distribution capacity service and to monetize any retain any revenue streams outside the PG&E contract.

**3.4 Eligibility/Minimum Conforming Bid**

Any type of DER
0.25 MW to 2 MW in 0.25 MW increments
Interconnected to Rincon substation feeders 1101, 1102, 1103 and 1104

[3] D.16-12-036, p.48

### 3.5 Terms and Conditions

| Key Contract Term | Description |
|---|---|
| Delivery Term | Seller must deliver distribution capacity through October 31, 2024 |
| Initial Energy Delivery Date | Seller to specify date, either June, 2020, June 2021 or June 2022. Seller must be online by April of the year when deliveries begin to allow for performance testing. |
| Price | Based on Seller Offer. Payment includes a fixed capacity price in $/kw-month, and may include a $/kwh price to be paid upon dispatch. |
| Operating Parameters | Participants must provide distribution capacity at these times:<br>3:00 PM through 9:00 PM, Monday through Sunday during the months of June through October. |
| Restricted Period | Participants may not add load during 3:00 PM through 9:00 PM, Monday through Sunday during the months of June through October, on days when distribution capacity has been dispatched |
| Scheduling | For projects that are capable of responding to a dispatch instruction, Buyer may dispatch the Project on a day-ahead basis by 8:00 a.m. the day prior the delivery day. Seller will install and maintain all equipment and communications systems necessary to respond to dispatch instructions at its own cost. |
| Project Site and Customers | Seller is solely responsible for acquiring customers and executing all necessary agreements to ensure delivery of distribution services. At any time during the delivery term, Seller may modify its customer portfolio provided that such change is done in accordance with safety provisions and modified customer portfolio reliably provides the distribution services contracted for. Seller must include in bid documentation how changes in customer portfolio will be communicated to and verified by Buyer. |

| | |
|---|---|
| Compensation | Seller to be paid a $/kw-month capacity payment based on delivered capacity. Payment may also include a $/kwh price when dispatched.<br><br>If Seller fails to deliver at least 90% of contract capacity when scheduled, $/kw-month payment will be reduced. (See term sheet) |
| Measurement and Verification | The amount of Distribution Services the Project delivers will be measured based on the Project's technology.<br><br>Energy storage: revenue-quality meter<br><br>Distributed generation: revenue-quality meter<br><br>Demand response: CAISO baseline methodologies, based on revenue-quality customer interval meters<br><br>Energy efficiency or permanent load shift: Agreed upon methodology that incorporates baseline metering<br><br>Seller may propose an alternative measurement and verification methodology in their bid. |
| Performance Testing | Prior to the Initial Energy Delivery Date, seller will perform an initial performance test. After the IDD, Buyer will have the right to test no more than once per calendar year. If Seller fails initial test Seller may request a re-test. If Seller fails the re-test that will be grounds for contract termination. |
| Seller Performance Assurance | Project Development Security. (i) $60/kW for new Projects or (ii) $25/kW for existing Projects.<br><br>Delivery Term Security equal to the maximum of (i) $125/kW and (ii) 10% of the sum of the highest Fixed Payments for any 36-month period during the Delivery Term. |

| | |
|---|---|
| CPUC Approval | If CPUC Approval has not occurred on or before 180 days from the date on which Buyer files the agreement with the CPUC seeking CPUC Approval, then either Party may terminate the agreement |
| Events of Default | Customary provisions in a PG&E contract, and will also include:<br>Failure to meet a critical milestone<br>Failure to meet IDD<br>Monthly distribution services delivered for any calendar year averages less than 75%<br>Performance test shows project provides less than 85% of contract capacity |

### 3.6 Double Counting/Double Payment

All of DPAG meeting # 3 and half of DPAG meeting #6 (see attached Appendix C and F, respectively) were devoted to a discussion on methodologies to be used in the RFO and subsequent contract negotiations to mitigate the negative consequences of double counting and/or double payment for DERs procured to provide distribution services for the IDER Incentive Pilots.

Double counting is a concern for the IDER Incentive Pilots because, as described by the IOUs in their presentation materials for DPAG meetings #3 and #6, each IOU has made some assumptions about future customer adoption of DERs in their distribution needs assessment process. If, in the IDER Incentive Pilots procurement process, DERs are procured that have already been presumed to be adopted by customers outside the IDER Incentive Pilots procurement process then the total DERs delivered in the area will fall short of the DERs needed to provide the distribution service and defer the investment. In other words, the IOUs must have some methodology in place to determine whether the DERs procured in the IDER Incentive Pilot procurement process are incremental to the DERs that have been assumed to be adopted by customers in the local area in the distribution needs assessment.

Double payment is also a concern for the IDER Incentive Pilots because each of the IOUs has ongoing incentive programs, tariffs and other solicitations which compensate customers in some fashion for adoption of DERs that may provide distribution services. For example all of the California IOUs have extensive energy efficiency and demand response programs that are funded by customers. Each IOU also administers a self-generation incentive program (SGIP) to incent customer adoption of distributed generation and energy storage technologies. The NEM tariff compensates customers who have installed distributed generation on-site. In addition all the IOUs are also conducting ongoing procurement processes for DERs such at the energy storage RFOs. Because of these ongoing DER sourcing activities it is important for the IOUs to ensure that DERs being procured and compensated under the IDER Incentive Pilot are not receiving duplicate payment for provision of distribution services.

During DPAG meetings #3 and #6 the Joint IOUs proposed that Method #4 from the Competitive Solicitations Working Group final report is the preferred methodology for mitigating double counting/double payment concerns for the IDER Incentive Pilots. Method #4, as shown in Appendix F, is essentially a methodology to guard against double counting/double payment by allocating vendor proposals into one of three tranches. Tranche one is for vendor proposals that are not currently sourced via an ongoing incentive program, tariff or other solicitation. Tranche two is for a vendor proposal that is partially sourced via an ongoing incentive program, tariff or other solicitation. Tranche three is for a vendor proposal this is wholly sourced through an ongoing incentive program, tariff or other solicitation. The discussion at DPAG Meeting #3 and #6 regarding double counting/double payment surfaced a number of concerns with the Joint IOUs proposed Method #4. The concerns fell into two general categories:

1. The ability for vendors to receive early feedback from the IOU regarding which tranche in Method #4 their proposal would fall into, and

2. The possibility that for energy efficiency, for which the IOUs have an extensive portfolio of existing incentive programs, Method #4 would be unduly restrictive.

In response to the concerns raised by the DPAG, for the IDER Incentive Pilot RFO, PG&E proposes to test an alternative option for proposals containing energy efficiency and/or distributed generation resources. The California Efficiency + Demand Management Council (CEEDMC, formerly CEEIC) suggested that rather than being evaluated using Method #4 vendors could instead chose to have their bids evaluated based on a pre-specified overlap factor (see Appendix G for CEEIC slide deck describing overlap factor calculation) . For the purpose of the IDER Incentive Pilot, PG&E will set the overlap factor at 15 percent for both energy efficiency and distributed generation resources consistent with the CEEIC suggested methodology[4]. If a vendor chooses the overlap factor option the value of their bid will be discounted by 15 percent to reflect the overlap between the vendor's proposal and energy efficiency and distributed generation resources that are assumed to be adopted in the IOUs distribution needs analysis in the absence of the IDER Incentive Pilot solicitation. If the Seller chooses this valuation option they will have the certainty with respect to incrementality treatment when bid are being developed and concerns that energy efficiency and distributed generation resources will be unduly impacted by Methodology #4 will also be mitigated.

### 3.7 Bid valuation

PG&E is seeking to procure distribution capacity services only. Thus, the valuation costs/benefits are simple, as described:

The DPAG evaluation meeting (DPAG meeting # 3) discussed the pros and cons of buying the distribution service only vs. the bundle of all potential energy products The primary concern expressed about purchasing distribution service only, was the potential incentive created for the Seller to focus on maximizing other revenue streams, and potentially risk compliance with the IOU distribution service contract. PG&E intends to minimize this risk by carefully monitoring deliveries, imposing strict performance standards (see T&C above), maintaining performance assurance, and if seller does not perform, terminating the contract and retaining such performance assurance.

### 3.8 Independent Evaluator

PG&E will contract with an Independent Evaluator ("IE") to oversee the process for the IDER RFO. PG&E will submit the IE's report on the IDER process as part of the advice letter that PG&E files seeking approval of IDER contracts.

## 4 Contingency Plan

The first half of DPAG Meeting #6 was devoted to issues around contingency planning for the IDER Incentive Pilots. The Joint IOU's characterized the key contingencies as: 1.) contingencies that arise during solicitation and contract negotiation phase; 2.) contingencies that arise during the deployment stage after a contract has been awarded; and 3.) contingencies that arise during the operational stage after the DERs have been deployed and are providing the distribution service. During DPAG meetings #6 and #7 three primary stakeholder concerns with contingency planning were raised:

1. If a contingency arises during the solicitation or contract negotiation stage wherein there are too few bids to provide the distribution service needed would the IOU default to the best available traditional wires solution or would

[4] The 15 percent overlap factor discounting is in addition to any discounting of bids based on evaluation of the effective local area delivery capacity of the resources.

the IOU attempt to reset and issue another RFO that corrects for issues identified in the initial RFO that may have contributed lack of DERs bid.

2. If a contingency were to arise during the deployment stage would the IOUs default to the best available traditional wires solution or would the IOUs attempt to go back and attempt to negotiate with the next best available DER vendor whose proposal was not accepted in the initial bid.

3. How will the IOUs manage contingencies related to uncertainty in needs assessments during the RFO solicitation or deployment stages? For example if the projected timing of the need is accelerated based on needs assessment updates in 2017/2018 distribution planning cycle.

In response to the concerns raised by the DPAG, for the IDER Incentive Pilot process PG&E proposes:

1. If a contingency should arise during the solicitation or contract negotiation stage, PG&E will perform a root cause analysis to determine the cause of the failure and the best corrective action. If the result of that root cause analysis determines that the contingency was caused by one or more failures in the solicitation process that can be corrected, and time and regulatory processes allow, then PG&E will consider administering a revised IDER Incentive Pilot solicitation. If the root cause analysis, timing or regulatory process preclude a revised solicitation then PG&E will move forward with the best alternative wires solution in order to ensure the safe and reliable provision of distribution services to our customers.

2. If a contingency should arise during the project deployment or project operations stage, PG&E will perform a root cause analysis to determine the cause of the failure and the best corrective action. If the root cause analysis, timing and regulatory process allow, PG&E will first seek to replace the failed DER with the best available alternative DER. If the root cause analysis, timing or regulatory process preclude replacement of the failed DER with the next best alternative DER then PG&E will move forward with the best alternative wires solution in order to ensure the safe and reliable provision of distribution services to our customers.

3. In order to mitigate contingencies related to changes in the timing and/or size of the need PG&E proposes to procure the DERs in tranches with the first tranche to be deployed with in-service date of June 2020, the second

tranche to be deployed with in-service date of June 2021, and the third tranche to be deployed with in-service date of June 2022. All three tranches will be obligated to deliver through October 2024.

## 5 Recording and Recovery of Procurement Costs in Integrated Distributed Energy Resources Account (IDERA)

Pursuant to OPs 21, 22 and 23 of D.16-12-036, PG&E requests approval of its forecast of expected incremental administrative costs for its IDER Incentive Pilot, including for the solicitation process and other non-procurement costs. Pursuant to PG&E's previously filed and approved Advice Letter 5017-E, the forecast costs approved in this advice filing are pre-approved for recording and recovery and will be reviewed by the Commission in PG&E's next GRC. Any administrative costs exceeding the forecast approved in this advice letter are subject to a reasonableness review. The annual distributed energy resources contract costs, having been pre-approved, will be recovered over the life of the contract.

PG&E's forecast for administrative costs associated with the IDER pilot project is included in a confidential attachment to this advice letter (see Appendix K). The breakdown of this estimate and a preliminary estimate of the cost-effectiveness cap for the solicited distributed energy resources are also presented in the confidential attachment to this advice letter.[5] The calculations of these estimates respond to the directive on page 62 of D.16-12-036 that states: *The Utilities shall present an estimation of the administrative costs in the Tier Three Advice Letter required in Step Three of the Incentive Pilot. This estimate and a cost-effectiveness cap for the solicited distributed energy resources projects should also be presented in a confidential attachment to the advice letter.*

PG&E may revise the initial cost-effectiveness cap shown in the confidential attachment based on additional information that becomes available between now and contract execution. Any revisions to the preliminary cost-effectiveness cap calculation shown in the attachment will be included in the Tier II Advice Letter requesting Commission approval of executed contracts for the IDER Incentive Pilot.

## 6 Commission Action Requested

Pursuant to OPs 14 and 15 of D. 16-12-036, PG&E requests that the Commission approve procurement of a potential cost-effective DER solution for its Santa Rosa (Rincon Substation) project. Pursuant to OP 15, PG&E requests that the Commission's Energy Division expeditiously implement Step Four of D.16-12-036 by hosting a workshop to discuss the contents of this advice letter. The Energy Division should also expeditiously establish a schedule to allow for protests or response to this advice letter

[5] IDER Decision 16-12-036, p.62

following the workshop and subsequently issue a proposed resolution addressing the advice letter.

**Tariff Revisions**

The filing would not increase any current rate or charge, cause the withdrawal of service, or conflict with any rate schedule or rule.

**Protests**

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, facsimile or E-mail, no later than July 6, 2017, which is 20 days after the date of this filing. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest shall also be sent to PG&E either via E-mail or U.S. mail (and by facsimile, if possible) at the address shown below on the same date it is mailed or delivered to the Commission:

Erik Jacobson
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B23A
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-1448
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

**Effective Date**

PG&E requests that this Tier 3 advice filing become effective upon Commission approval.

**Notice**

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service list for R.14-10-003. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Erik Jacobson
Director, Regulatory Relations

cc: Service List R.14-10-003

**Attachments**

Attachment A - Distribution Planning Advisory Group Meeting #1 - March 2, 2017
Attachment B - Distribution Planning Advisory Group Meeting #2 – March 16, 2017
Attachment C - Distribution Planning Advisory Group Meeting #3 – March 23, 2017
Attachment D - Distribution Planning Advisory Group Meeting #4 – March 30, 2017
Attachment E - Distribution Planning Advisory Group Meeting #5 – April 6, 2017
Attachment F - Distribution Planning Advisory Group Meeting #6 – April 13, 2017
Attachment G - California Efficiency + Demand Management Council Presentation
Attachment H - Independent Professional Engineer Presentation #1
Attachment I - Independent Professional Engineer Presentation #2
Attachment J1 - PG&E DRAFT RFO Protocol
Attachment J2 - Appendix B1 – B8 - Integrated Distributed Energy Resources Incentive Pilot RFO
Attachment J3 - Appendix C - Confidentiality Agreement Draft
Attachment J4 - Appendix D - Term Sheet for IDER Incentive Pilot
Attachment J5 - Appendix E – Finance Information
Attachment K - Forecast of Expected Incremental Administrative Costs and Preliminary Estimate of Cost Effectiveness Cap (Confidential)

# CALIFORNIA PUBLIC UTILITIES COMMISSION

## ADVICE LETTER FILING SUMMARY
## ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. **Pacific Gas and Electric Company (ID U39 E)**

| Utility type: | Contact Person: Yvonne Yang |
|---|---|
| ☑ ELC ☐ GAS | Phone #: (415) 973-2094 |
| ☐ PLC ☐ HEAT ☐ WATER | E-mail: Yvonne.Yang@pge.com and PGETariffs@pge.com |

| EXPLANATION OF UTILITY TYPE | (Date Filed/ Received Stamp by CPUC) |
|---|---|
| ELC = Electric GAS = Gas<br>PLC = Pipeline HEAT = Heat WATER = Water | |

Advice Letter (AL) #: **5096-E** **Tier: 3**

Subject of AL: **Request for approval of distributed energy resource (DER) procurement for the IDER Utility Regulatory Incentive Mechanism Pilot (Incentive Pilot)**

Keywords (choose from CPUC listing): Compliance

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other ______________________

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: D. 16-12-036

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL: ____________________

Is AL requesting confidential treatment? If so, what information is the utility seeking confidential treatment for: Yes

Confidential information will be made available to those who have executed a nondisclosure agreement: N/A

Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information: Shaila Narang (415) 223-6110

Resolution Required? ☑Yes ☐No

Requested effective date: **Upon Commission approval** No. of tariff sheets: N/A

Estimated system annual revenue effect (%):N/A

Estimated system average rate effect (%):N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed: N/A

Pending advice letters that revise the same tariff sheets: N/A

Protests, dispositions, and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

**California Public Utilities Commission**
**Energy Division**
**EDTariffUnit**
**505 Van Ness Ave., 4th Flr.**
**San Francisco, CA 94102**
**E-mail: EDTariffUnit@cpuc.ca.gov**

**Pacific Gas and Electric Company**
**Attn: Erik Jacobson**
**Director, Regulatory Relations**
**c/o Megan Lawson**
**77 Beale Street, Mail Code B23A**
**P.O. Box 770000**
**San Francisco, CA 94177**
**E-mail: PGETariffs@pge.com**

Advice 5096-E

June 16, 2017

**Attachment A**

Distribution Planning Advisory Group Meeting #1 - March 2, 2017

# IDER Proceeding's Incentive Pilot: Distribution Planning Advisory Group (DPAG) Kick-Off Meeting

## March 2, 2017

# Safety Check

- Be aware of your surroundings
- Participate safely
- Don’t drive while attending webinar
- Utility teams will follow established procedures in case of any emergency
  - For example, duck/cover/hold/evacuate if an earthquake

# Meeting Agenda

| No. | Duration (Minutes) | Topic Description | Presenter |
|---|---|---|---|
| 1 | 10 | Meeting Objectives/ Roll call | Diana Genasci |
| 2 | 15 | IDER Decision overview and progress to-date | Diana Genasci |
| 3 | 10 | Introduce IPE and Technology Neutral Pro forma Consultant | Diana Genasci |
| 4 | 30 | DPAG Charter  Overview | Dhaval Dagli |
| 5 | 20 | IOU Planned Consultations With DPAG | Dhaval Dagli |
| 6 | 15 | DPAG  Proposed Schedule | Joe McCawley |
| 7 | 10 | Meeting Close – Next Steps, including reminder about NDAs | Joe McCawley |

# Meeting Objectives

- Update DPAG participants on efforts to implement near-term elements of the IDER Decision
  - Technology Neutral Pro Forma Consultant;
  - Independent Professional Engineer (IPE); and
  - Formation of Distribution Planning Advisory Group (DPAG)
- Review DPAG's charter, and provide clarifications to further common understanding of DPAG roles and responsibilities
- Discuss future meetings and agree on a meeting schedule
- Discuss next steps including remaining NDAs

# IDER Decision Overview

- On December 22, 2016, the Commission issued Decision D.16-12-036 addressing the Competitive Solicitation Framework and Regulatory Incentive Pilot in the IDER proceeding.
- Adopts a technology neutral competitive solicitation framework for Distributed Energy Resources (DERs) that can be deployed to defer traditional distribution infrastructure and establishes a regulatory process to oversee these solicitations
- Authorizes a pilot to test a regulatory incentive mechanism through which a utility can earn 4% pre-tax incentive on annual payment to DERs
- Requires each utility to select at least one deferral project for the pilot, but allows the utility to select up to four projects
- Specifies steps related to pursuing the incentive pilot, including forming a Distribution Planning Advisory Group, hiring an Independent Professional Engineer and hiring a technology neutral Pro forma consultant

# IDER Decision – Seven Steps

- **Step 1- Formation of Advisory Group for The Pilot:** within two (2) months of the issuance of the Decision (i.e., by February 22, 2017) the IOUs must establish the DPAG and hire the IPE
- **Step 2- Identification of Projects:** within four (4) months of the issuance of the Decision (i.e., by April 22, 2017) the IOUs must identify at least one, but up to four projects for the Incentive Pilot, in accordance with the Decision
- **Step 3- Advice Letter Process**: within six (6) months of the issuance of the Decision (i.e., by June 22, 2017) each IOU shall file a Tier Three Advice Letter requesting approval to procure a DER solution
- **Steps 4-7:** include solicitation approval process, utility holding a solicitation, contract approval process via a Tier Two advice letter, and a two-part pilot reporting process.

# Progress To-date

- Hired Technology Neutral Pro Forma Consultant
- Hired IPE
- Formed the DPAG

# Pro-forma Consultant

- OP 6  required PG&E, in consultation with SDG&E, SCE, and the Commission's Energy Division, to hire an industry consultant with expertise in distributed energy resources (DERs) and contracting
- After requisite consultations, Mr. Alan Taylor of Sedway Consultants, Inc. was selected as the Technology Neutral Pro Forma Consultant
  - Mr. Taylor has over 33 years of experience in the energy industry with over 15 years in providing independent evaluations of utility solicitations for conventional and distributed energy resources
  - He has requisite experience with DERs and has a detailed record of independent evaluation and consultation with all three utilities in CPUC proceedings
  - He has participated in the utilities' Procurement Review Groups (PRG)

# Independent Professional Engineer

- On December 30, 2016, the Utilities sent a communication via email to the Distribution Resources Plan (DRP) and IDER service lists, inviting recipients to propose qualified IPE candidates.
- Separately, the Utilities also reached out to 24 individual firms and educational institutions for potential qualified candidates within their organizations
- Short-listed candidates were interviewed by the Energy Division and the utilities
- Mr. Bernard (Barney) Speckman of Nexant Inc. was selected by the Energy Division as the Independent Professional Engineer
  - BS EE – Cal Poly SLO // MS EE/CS – UC Berkeley // Program for Management Development – Harvard Business School
  - 31 years utility experience (system planning, operations, power contracts)
  - 16 years consulting experience (renewables integration, market design, system operations)

# Distribution Planning Advisory Group

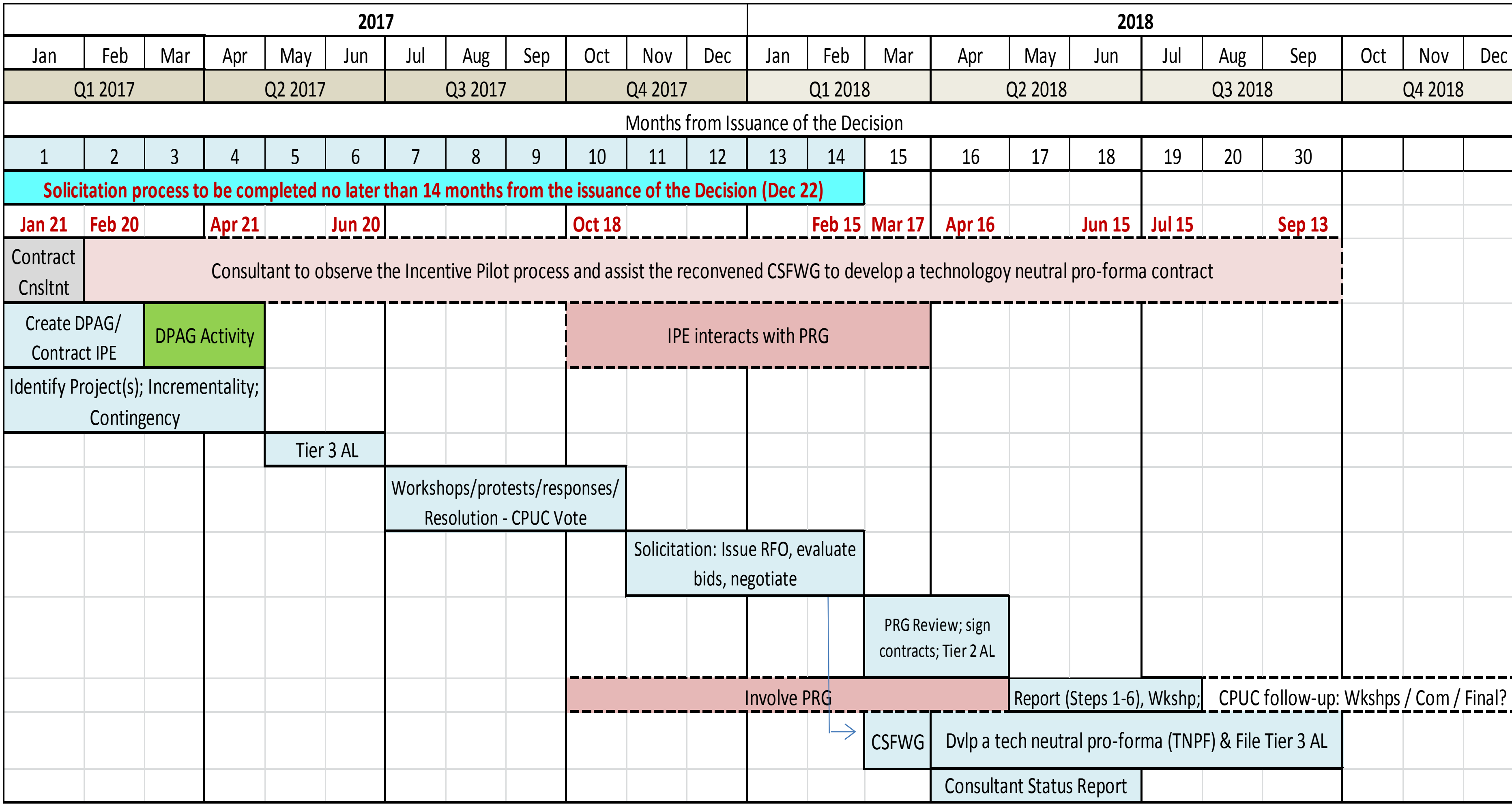
- **One DPAG:** PG&E, SCE and SDG&E jointly formed a single DPAG as required by the Commission.
- **Interim DPAG**: This DPAG has been formed on an interim basis for the purpose of the pilot program approved in D.16-12-036.
- **Participation:** Includes Commission staff and interested non-market and market participant parties, with the latter restricted from receiving certain information.
- **DPAG Duties and Responsibilities**: The DPAG shall advise and be consulted by the IOUs on the process for consideration of proposed distribution deferral pilot projects, contingency plans, proposed counting method and valuation components for the Incentive Pilot.
- **DPAG Administration:** The IOUs will administer and facilitate the DPAG process; will provide an agenda for each DPAG meeting beforehand; meeting materials, will be distributed at least 24 hours in advance of the meeting, barring unforeseen circumstances; meeting summaries will be distributed following each meeting, including a list of all DPAG participants who attended that meeting.

# DPAG Consultations

**DPAG meetings will be scheduled from March 13 to April 22 and will address the following:**

| | |
|---|---|
| Project Identification | • Overview of distribution planning process<br>• Criteria for identifying potential deferral projects<br>• Prioritization within potential projects<br>• Final selection, including number of projects selected for the pilot |
| Contingency Plans | • Develop contingency plans to be deployed in the event DER-based solutions fail to materialize, for example, due to:<br>  • Limited or cost-prohibitive market response for DER-based solutions;<br>  • DER project failures during development;<br>  • DER project underperformance during operations; or<br>  • DER project under-procurement due to forecasting errors or double counting |
| Double Counting | • Development of a counting method either as described in or as an alternative to the methods in the August 1, 2016 Competitive Solicitation Framework Working Group Report to ensure distributed energy resources procured are incremental to those forecasted.<br>  • Such method will be consistent with principles (a) through (g) in Ordering Paragraph 3 of the IDER Incentive Pilot Decision |
| Evaluation Methodology | • For purposes of the pilot, consider additional valuations and methodologies for defining valuations, as required in the IDER Incentive Pilot Decision page<br>  • These discussions will build upon the valuation components included in Appendix A of the Decision |

# Overall Incentive Pilot Schedule



# Proposed DPAG Meeting Schedule

| DPAG Meetings | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Mar | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | Apr | | | | | | | | | | | | | | | | | | | | |
| 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 |
| | | Kick-off WebEx | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Review Potential Deferral Projects: Utility Specific | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Discuss Contingeny Plans: Utility Specific | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Incrementality Methodology: Utility Specific | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Utility 1 | | | | | | | | | | | | | | | W | | | | | | | I-P | | | | | | | | | | | | | | W | | | | | | | | | | | | | | W | |
| Utility 2 | | | | | | | | | | | | | | | W | | | | | | | I-P | | | | | | | | | | | | | | or | | | | | | | | | | | | | | W | |
| Utility 3 | | | | | | | | | | | | | | | W | | | | | | | I-P | | | | | | | | | | | | | | I-P | | | | | | | | | | | | | | W | |
| Valuation component discussion: Joint Utility Meeting | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Utility 1 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | W | | | | | | | | | | | | | | W | | | | | | | | |
| Utility 2 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | or | | | | | | | | | | | | | | or | | | | | | | | |
| Utility 3 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | I-P | | | | | | | | | | | | | | I-P | | | | | | | | |

- Represents each IOU having a weekly meeting with the DPAG, either via teleconference, webinar, or in-person, beginning the week of Mar 13
- Agenda to be issued 24 hrs before the meeting; identify if the meeting will exclude market participants
- Each Webinar / Teleconference will typically be two hours
- In-person meetings to be held in SF; either joint IOU or 2 hrs with each IOU

# DPAG Participants Need to Submit NDAs

- Page 4-5: Parties need to self-identify their company as either a market participant (E.3) or a non-market participant (F),
- Page 11: Information for a company’s authorized representative. If multiple participants from the same company, need only one per company. But still need to complete for each of the three NDAs (one for each IOU), and
- Page 12: Each individual interested in participating in the DPAG needs to provide a signed Disclosure Certificate for each of the three provided NDAs (one for each IOU).

# Wrap-up and Next Steps

- Agree on meeting schedule, so that utilities can schedule DPAG meetings
- NDAs must be received before able to participate in future DPAG meetings
- Utilities welcome any additional feedback

# Contact List

**CPUC(ED)** -- Chari Worster, Chari.Worster@CPUC.CA.Gov, 415 703-1585

**PG&E** -- Richard Aslin, Richard.Aslin@PGE.com, 415 973-1101

**SCE** -- Patrick Hodgins, Patrick.Hodgins@sce.com, 626 320 9883

**SDG&E** -- Joe McCawley, JMcCawley@SempraUtilities.com, 858 503-5302

Advice 5096-E

June 16, 2017

# Attachment B

Distribution Planning Advisory Group Meeting #2 – March 16, 2017

# IDER Incentive Pilots DPAG Meeting # 2

## Joint IOU Presentation

## Distribution Planning Process & Proposed Distribution Investment Deferral Framework

**March 16, 2017**

# Meeting Agenda

| | |
|---|---|
| Safety Message | 10:05-10:10 |
| Role Call | 10:10-10:15 |
| Meeting Protocols | 10:15-10:20 |
| Overview of Distribution Planning Process | 10:20-10:45 |
| Discussion and Q&A | 10:45-11:00 |
| Overview of Proposed Initial DIDF Screens and Prioritization | 11:00-12:00 |
| Lunch Break | 12:00-1:00 |
| Discussion and Q&A | 1:00-1:45 |
| Summary/Next Steps/Preview of Next Meeting | 1:45-2:00 |

# Safety Message and Role Call

Safety Message: Please take a moment to observe your surroundings. Make a plan about what you will do in the event of a health emergency, a fire, an earthquake or an active shooter. We will pause 60 seconds for that purpose.

Role Call: Please respond affirmatively when your name is called. You must be logged onto the WebEx by your first and last name. This is done when you first log onto the WebEx. If you have not done that please exit the WebEx and log on again using your first and last name. Any entity not clearly identified in the participants by first and last name or entities who are not registered as DPAG participants on our current DPAG roster will be disconnected by the host.

- SDG&E Staff // SCE Staff // PG&E Staff
- IPE // TNPF Consultant
- CPUC-ED // CPUC-ORA // CEC // CAISO
- Non-Market Participants // Market Participants

# Meeting Protocols

- Please mute your phones when you are not speaking.
- Please do not put this meeting on hold.
- We will take Questions/Comments at the end of each agenda item or if agenda items take more than 10 minutes we will take questions at reasonable intervals within the agenda item.
- Please state your name and who you represent prior to asking you question or providing your comment.
- We will "parking lot" items that cannot be resolved via discussion in this meeting and take them up in the afternoon or at future meetings if appropriate.

# Distribution Planning Process (DPP)

**DER Alternative Mitigations Considered** (steps 4–5)

**1 — Develop Assumptions** → **2 — Distribution Planning Assessment** → **3 — Distribution Grid Needs** → **4 — Evaluate Alternatives** → **5 — Implement Preferred Alternative**

### 1. Establish Baseline Assumptions

- Load and DER growth and loading profiles
- Existing distribution project status
- Circuit capabilities

### 2. Assess Historical and Projected Performance

- Will current grid infrastructure support projected loading and/or DER deployments safely and reliably

### 3. Determine Attributes of Distribution Needs

- Distribution capacity
- Voltage support
- Reliability
- Resiliency

### 4. Determine Preferred Alternative

- Estimate costs and evaluate technical performance
- Determine contingency plan
- Select best mitigation alternative

### 5. Traditional "Wires" Project:

- Engineer, Procure materials and Construct
- Track project milestones
- Incorporate as assumption for next planning cycle

**NEW: -- DER Alternative Project::**

- Conduct RFO, review bids, select best project or portfolio of projects, negotiate contracts
- Track project milestones
- Incorporate as assumption for next planning cycle

**7 to 10 months** (steps 1–4)

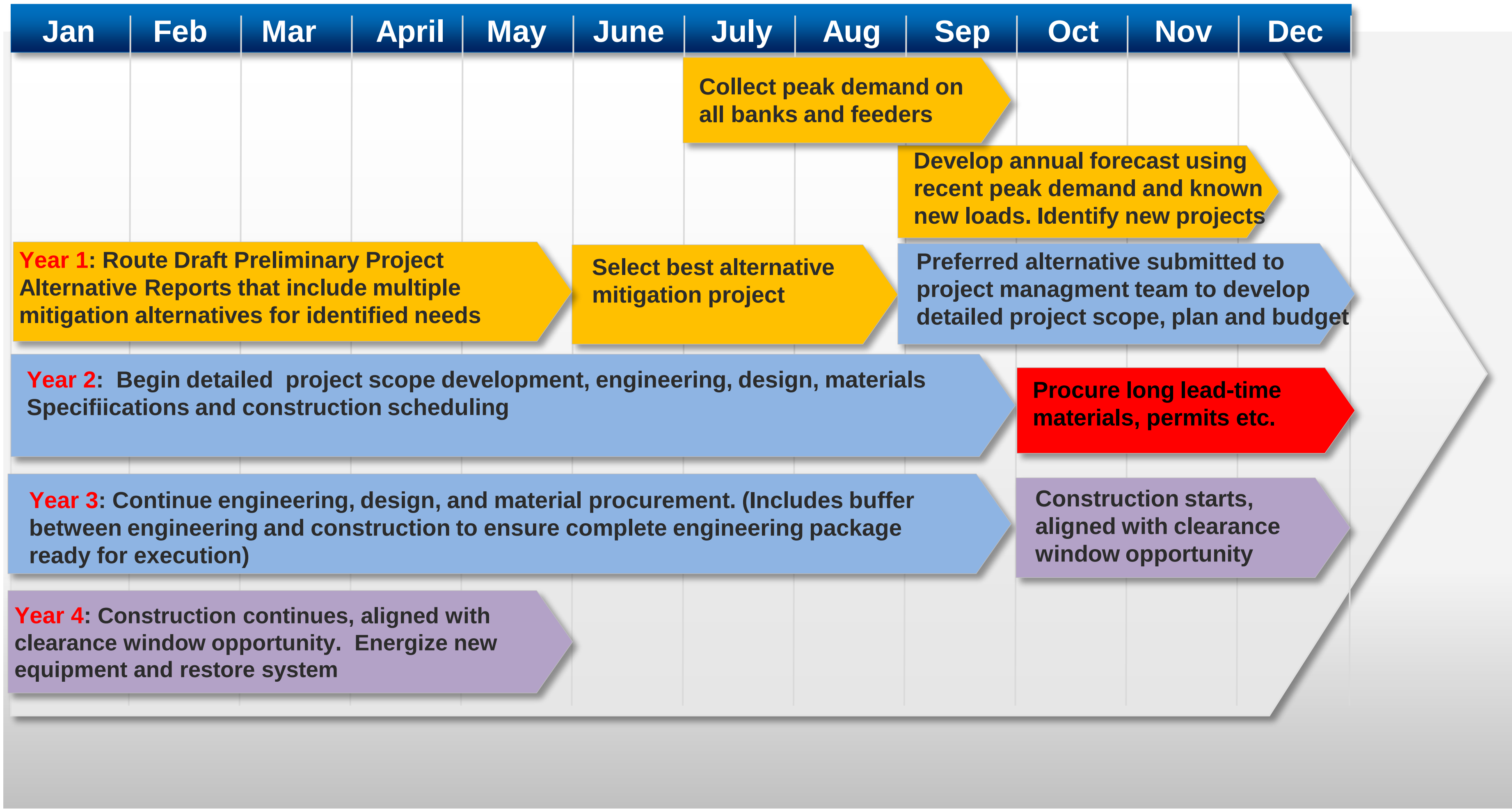
**12 to 60 months** (step 5)

**Distribution Planning Process (DPP) spans approximately 7-10 months each year and identifies projected distribution capacity requirements and mitigation plans to address projected deficiencies.**

**Project Implementation (PI) length depends on the project, from fuse replacement (12 months) to new substation (60+months).**

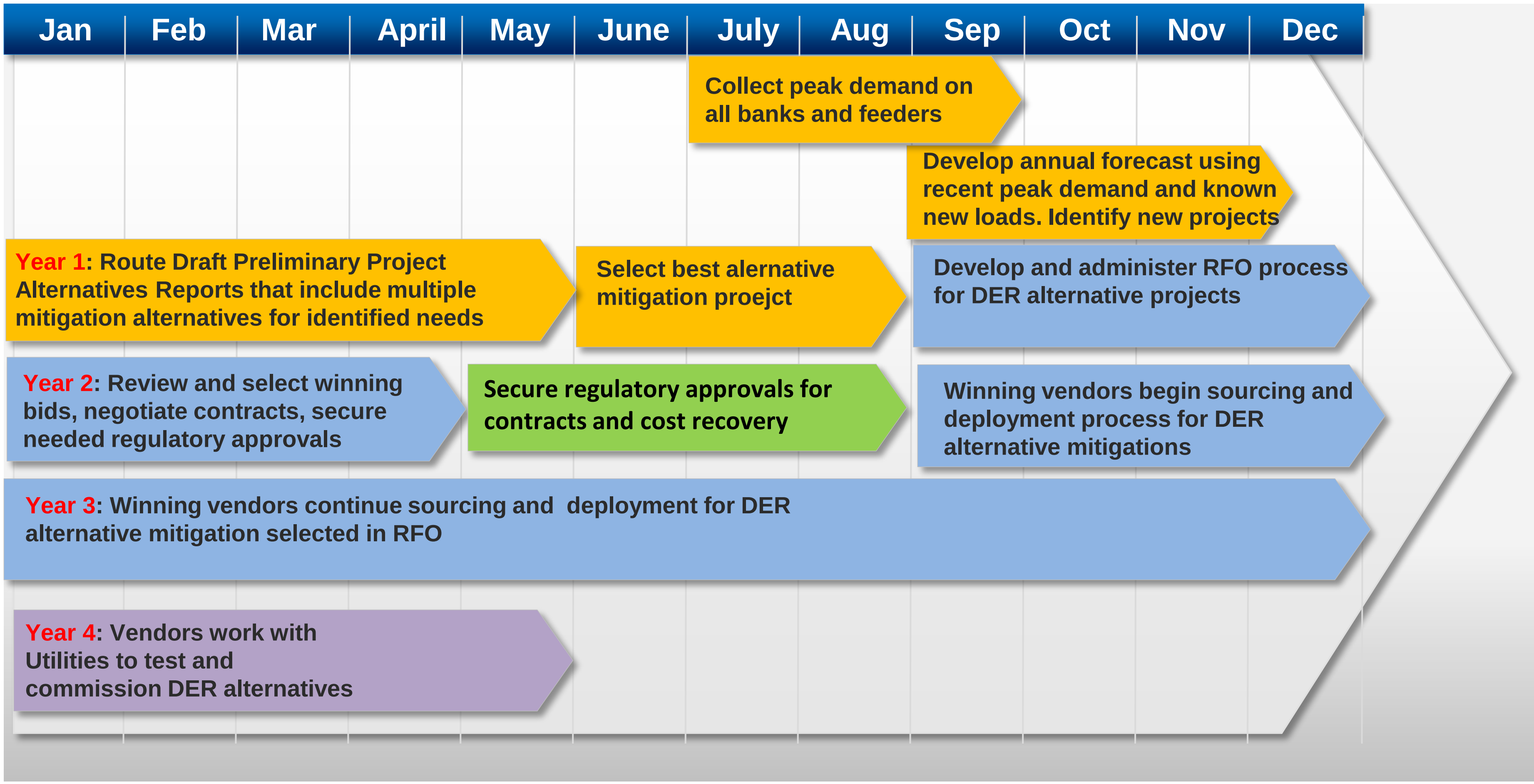
# Illustrative Traditional "Wires" Project Timeline

Illustrative timeline for adding or replacing transformer bank at an existing substation or adding a new feeder to an existing or new substation bank. Replacing fuses on lines could be as little as 12 months for engineering deployment and commissioning. Reconductoring a segment of an existing line could be as little as 18 months. Existing substation upgrades generally 36 to 60 months. Building a new substation could be 60 months or longer.



# Illustrative DER Alternative Project Timeline

Illustrative timeline for DER Alternative Project of medium size and complexity. Joint IOUs would expect that DER deployments would follow a similar timeline to traditional project deployment with smaller and less complex deployments taking as little as 12 months post contracting and larger more complex deployments taking as much as five years to complete.



# Contingency Planning

The amount of lead-time needed for the DER Alternative Project is a function of three things:

1. The scope and complexity of the DER alternative project
2. The scope and complexity of the next best alternative project
3. The ability to observe and enforce DER alternative project milestones

As can be seen from the previous project timing slides:

- The minimum lead-time, including sourcing, deployment and commissioning for a DER alternative project would be estimated 18 months :
    - Estimated 9 months to conduct the RFO and sign contracts plus and secure regulatory approvals
    - Estimated 12 months to deploy and commission.

- The minimum lead-time to off ramp to the next best alternative project would be estimated 18 months:
    - Beginning with the need to procure materials and permits
    - Assuming that detailed contingency project engineering and design is running in parallel with DER Alternative project sourcing and deployment and the costs incurred for contingency planning can be recovered
    - Assuming that DER alternative project milestones are observable and strictly enforced

# Overview of Proposed Initial DIDF Screens

| First Step – Identify Candidate DER Deferral Projects | | | |
|---|---|---|---|
| **Two Screens Used for This Step** | | | |
| **Project Timing** | XX months from time RFO is issued (IDER Incentive Pilots RFO scheduled to be issued October 2017) | Only projects with a specified in-service date will be considered for IDER Incentive Pilots:<br>• Allows time to source, deploy and commission DER mitigation options<br>plus<br>• Allows time to off-ramp to next best alternative if DER mitigation fails to meet need | For the IDER Incentive Pilots the Joint IOUs recommend considering projects with in-service dates of summer 2020 or later. |
| | | | |
| **Project Services** | Four Distribution Services Identified in D. 16-12-036 | 1. Distribution Capacity<br>2. Voltage Support<br>3. Reliability (Back-Tie)<br>4. Resiliency (micro grid) | |

# Overview of Proposed Candidate Project Prioritization Process

**Evaluate and Prioritize Candidate Projects:** In this step the utilities prioritize the candidate projects based on a multi-dimensional analysis which includes consideration of technical, market, and financial criteria including:

- ✓ DER Attribute Requirements
  - Each candidate project will be more closely reviewed to determine the amount of DER or portfolios of DERs required to meet the distribution service
- ✓ Project Timing Certainty
  - Each candidate project will be more closely reviewed to determine the certainty of the project in-service date
- ✓ Financial Assessment
  - DER Attribute Requirements vs. Wires alternative for each project will be assessed
- ✓ Market Assessment
  - The number and composition of customers in each project area will be assessed to determine the ability of BTM DER solutions to meet the needs identified

– Q & A

– Summary/Next Steps

– Preview of Next DPAG Meeting

Advice 5096-E

June 16, 2017

# Attachment C

Distribution Planning Advisory Group Meeting #3 – March 23, 2017

# IDER Incentive Pilots DPAG Meeting # 3

## Joint IOU Presentation

## Valuation Components

### March 23, 2017

# Meeting Agenda

| | |
|---|---|
| Safety Message and Roll Call | 10:05-10:15 |
| Meeting Protocols | 10:15-10:20 |
| Background: Competitive Solicitation Framework WG | 10:20-10:30 |
| Overview: Evaluation Steps | 10:30-10:45 |
| List of Potential Valuation Components | 10:45-11:15 |
| Break | 11:15-11:30 |
| Discuss New Valuation Components | 11:30-12:00 |
| Quantify any Qualitative Factors | 12:00-12:30 |
| Summary/Next Steps/Preview of Next Meeting | 12:30- 1:00 |

# Safety Message and Role Call

Safety Message: Please take a moment to observe your surroundings. Make a plan about what you will do in the event of a health emergency, a fire, an earthquake or an active shooter. We will pause 60 seconds for that purpose.

Role Call: Please respond affirmatively when your name is called. You must be logged onto the WebEx by your first and last name. This is done when you first log onto the WebEx. If you have not done that please exit the WebEx and log on again using your first and last name. Any entity not clearly identified in the participants by first and last name or entities who are not registered as DPAG participants on our current DPAG roster will be disconnected by the host.

- SDG&E Staff // SCE Staff // PG&E Staff
- IPE // TNPF Consultant
- CPUC-ED // CPUC-ORA // CEC // CAISO
- Non-Market Participants // Market Participants

# Meeting Protocols

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- Please do not put this meeting on hold.
- We will take Questions/Comments at the end of each agenda item or if agenda items take more than 10 minutes we will take questions at reasonable intervals within the agenda item.
- Please state your name and who you represent prior to asking you question or providing your comment.
- We will “parking lot” items that cannot be resolved via discussion in this meeting and take them up in the afternoon or at  future meetings  if appropriate.

# Background

- The Competitive Solicitation Framework (Framework) Working Group (WG) developed consensus on
  - the evaluation process
  - the guiding principles
  - the matrix of valuation components under quantitative and qualitative categories,

  and submitted the final report to the Commission on Aug 1, 2016

- The Decision (D.16-12-036) approved WG's consensus on:
  - Use of least-cost, best-fit framework for the solicitation evaluation
  - Principles for developing a solicitation method:
    - Consider the potential services beyond what is asked in the solicitation and other conceivable benefits and costs, provided by the distributed energy resource as qualitative factors
    - Continue to refine the evaluation method and integrate lessons learned
    - Avoid double counting of benefits and costs
  - Set of potential quantitative/qualitative valuation components as the viable starting point

# Further Direction from the Commission for the Utilities and DPAG

- Continue discussion to further develop the valuation components list and consider additional quantitative and qualitative factors

- Discuss methodologies to quantify any components that are currently characterized as qualitative

- Then, if consensus is reached, additional valuation components and methodologies may be used in the Incentive Pilot

# Overview of Evaluation Steps

1. Initial screen
   – Completeness and conformity of the project proposals

2. Quantitative valuation
   – Cost-benefit analysis of each project proposal is performed by estimating the Net Present Value (NPV) from the projected benefits and cost streams by using the applicable quantitative factors to the proposal and the discount rate of the utility

3. Portfolio selection including qualitative consideration
   – Selection method can vary from simple rank ordering to complex optimization exercise depending on the RFO need specifications
   – Considers mutual exclusivity, inclusivity, contingencies, volume limits – options offered by the seller for utility to choose to best fit the need

# List of Potential Valuation Components

| Quantitative Factors | Qualitative Factors |
|---|---|
| Resource Adequacy (RA) value | Project viability |
| Energy value benefit | Voltage and other power quality services |
| Ancillary Service (A/S) value benefit | Equipment life extensions |
| Renewable Portfolio Standard (RPS) benefit | Societal net benefits |
| Reduced Greenhouse Gas (GHG) benefit | Other factors, such as:<br>- Supplier diversity (including DBE)<br>- Counterparty concentration<br>- Site diversity<br>- Technology/end use directory to help market transformation |
| Renewable integration cost/reduced cost benefit | |
| Distribution deferral value | |
| Transmission deferral value | |
| Contract payment cost | |

Appendix has the description and methodology of valuation components

Note: This list contains potential valuation components. The components used in a particular RFO will depend on the need detailed in the RFO and will be listed out by each utility at the time of RFO launch.

# Other Potential Valuation Components

## Quantitative

## Qualitative

- Contribution towards other mandates
- Adherence to model agreement T's & C's
- Portfolio fit

# Quantify any Qualitative Factors

– Summary/Next Steps

– Preview of Next DPAG Meeting

# Appendix

# Quantitative: Net Present Value (NPV)

Net Present Value is calculated for each Offer as follows:

- Present Value of  Benefits – Present Value of Costs

- Where Benefits =

    - RA (Capacity) Value
    - Energy Value
    - Ancillary Services Value
    - RPS Benefit
    - Reduced GHG Emissions Benefit
    - Renewable Integration Cost/Reduced Cost Benefit
    - Distribution Deferral Value
    - Transmission Deferral Value

- And Costs = Contract Payments Costs (including Fixed and Variable Costs)

# Quantitative: Resource Adequacy Value

- Resource Adequacy (RA), including system, local, and flexible, attributed to each resource are established under the guidance of the current CPUC net qualifying capacity counting rules
- If a resource’s operational capabilities generally fall under a category described by the CPUC for RA accounting rules, the rule should be applied directly.
- If no such category is identified, utilities may use program/technology specific studies/proceedings to estimate the impact of a resource on peak load or assess the contribution to peak load through their own analysis.
- Resources that act as load reducers may receive adjustments to their RA benefits, if any, to reflect avoided T&D losses and RA reserve margin requirements.

# Quantitative: Energy Value Benefit

- Energy Value Benefit is the value attributed to must-take resources based on the bid's expected generation delivery profile.
- For dispatchable resources, operations of the resource should be projected using the economic dispatch principle based on the bid's operating characteristics, operating costs, and market services offered.
- Resources which are expected to act as load reducers may receive adjustments to their energy quantity benefits to reflect distribution avoided losses.
- The energy price forecast is generally established using forward market data and fundamental price models.  Location-specific adjustments are conducted to reflect associated congestion and loss values forecasts.

# Quantitative: Ancillary Services (A/S)

- Ancillary Services (A/S) Value Benefit is projected based on first determining if a resource is capable of providing (A/S). If a resource is capable of providing A/S, then similar methodologies as energy amount forecast should be used to determine the A/S value to be attributed to each resource.

# Quantitative: Renewable Portfolio Standard (RPS) Benefit

- Eligible renewable DERs that count toward utilities' compliance requirements should receive RPS Benefit.
- The RPS benefit of a resource is calculated from the generation delivery profile.
- Load reducing DERs may also receive RPS benefits as these resources may result in a reduced RPS compliance requirement.
- The reduced RPS compliance requirement is calculated based on the total reduced bundled load projection from the resource and RPS standard targets

# Quantitative: Reduced GHG Emissions Benefit

- Load reducing DERs or renewable DERs should receive a benefit of reduced combustion-related GHG compliance obligations and corresponding costs

- There is not a separate quantification of this benefit as DERs receive the value of avoiding GHG emissions via the value of reduced generation need and associated energy costs

- Emission costs are embedded into LMP prices.

# Quantitative: Renewable Integration Cost/Reduced Cost Benefit

- Renewable resources require integration with flexible resources to firm intermittent output. For DERs in which renewable integration costs are applicable, the Renewable Integration Cost Adder (RICA) methodology from the RPS proceeding should be employed.

- Alternatively, other DERs can reduce the cost of integrating intermittent renewable generation by providing the operation flexibility of system needs, thus reducing system operation cost which otherwise would have been incurred in acquiring flexible resources.

- However, to the extent this benefit is already reflected in flexible RA or ancillary services value, it is appropriate to not double count this benefit.

# Quantitative: Distribution Deferral Value

- As identified in the DRP's LNBA methodology, deferred distribution components should include:
  - Sub-transmission, Substation and Feeder Capital and Operating Expenditures
  - Distribution Voltage and Power Quality Capital and Operating Expenditures
  - Distribution Reliability and Resiliency Capital and Operating Expenditures
- The Working Group proposed develop deferral values using the Real Economic Carrying Charge (RECC) method based on the approach being developed in the DRP.
  - The factors in this analysis should be the installed cost the operating and maintenance cost, project life, return on investment, and discount rate.
- Normalize deferral value into $/MW or $/MWh depending on the deferral requirement specification (ex. Capacity/energy/profile)
- Attribute the deferral value (benefit) by estimating the contribution of the specific DER towards deferral requirement based on
  - Temporal coincidence
  - Geographical coincidence
  - Effectiveness factor

# Quantitative: Transmission Deferral Value

- Transmission deferral value should be analyzed based on the cost of traditional grid investment and by identifying system characteristics (needs) driving the need for the transmission projects, such that a deferral value or avoided cost may be calculated.

- Factors in this analysis could include the interrelationship between transmission system planning and distribution system planning.
  - Coincident peak between DER and transmission will need to be taken into account to determine any potential contributions of DERs in deferring transmission capital and operating expenditures.

# Quantitative: Contract Payment Costs

- Contract costs are comprised of capacity payments and/or energy payments (i.e. fixed costs and variable costs).

# Qualitative: Project Viability, Voltage and Other Power Quality Services

- Project viability assessment includes factors such as developer experience, O&M experience (proven track record), commercial technology, reasonableness of delivery date, and interconnection progress.
- Voltage and other power quality services stream not identified as DER portfolio need during solicitation, if deemed to be providing value to the system could be considered while selecting bids.

# Qualitative: Project Viability, Voltage and Other Power Quality Services, Equipment Life Extension

- If DER bids are deemed to have impact on extending/reducing the distribution equipment life, the attribute could be considered as part of qualitative consideration while selection, as secondary benefit or cost.

# Qualitative: Societal Net Benefits

- As directed by the Commission in the IDER Incentive Pilot decision, the societal test valuation component shall not apply to this pilot as it is still being explored on a separate track in IDER proceeding.

# Attachment D

Distribution Planning Advisory Group Meeting #4 – March 30, 2017

# IDER Incentive Pilots DPAG Meeting # 4

## Joint IOU Presentation

## Double Counting / Incrementality

### March 30, 2017

# Meeting Agenda

| | |
|---|---|
| Safety Message and Roll Call | 10:05 - 10:15 |
| Meeting Protocols | 10:15 - 10:20 |
| Background: Competitive Solicitation Framework WG | 10:20 - 10:30 |
| Graphical Description of Incrementality Issue | 10:30 - 10:45 |
| Utility's Proposed Incrementality Method(s) | 10:45 - 11:45 |
| Lunch | 11:45 - 1:00 |
| NRDC Questions and Discussion | 1:00 - 2:00 |
| Summary/Next Steps/Preview of Next Meeting | 2:00 - 2:15 |

## Double-Counting of Services per D. 16 12 036

- The March 24, 2016 ruling identified seven elements of a competitive solicitation framework, with one being specific to incrementality, and required The Competitive Solicitation Framework Working Group (CSFWG) to develop consensus on methodologies to count services provided and ensure no duplication with procurement in other proceedings, i.e., ensure these services are incremental to existing efforts and avoid double-counting of resources and/or services. – page 18-19

- The CSFWG's Final Report, filed Aug 1, 2016, identified five different methods that had been proposed by various CSFWG participants, and informed that consensus had not been reached on any of them. – page 20

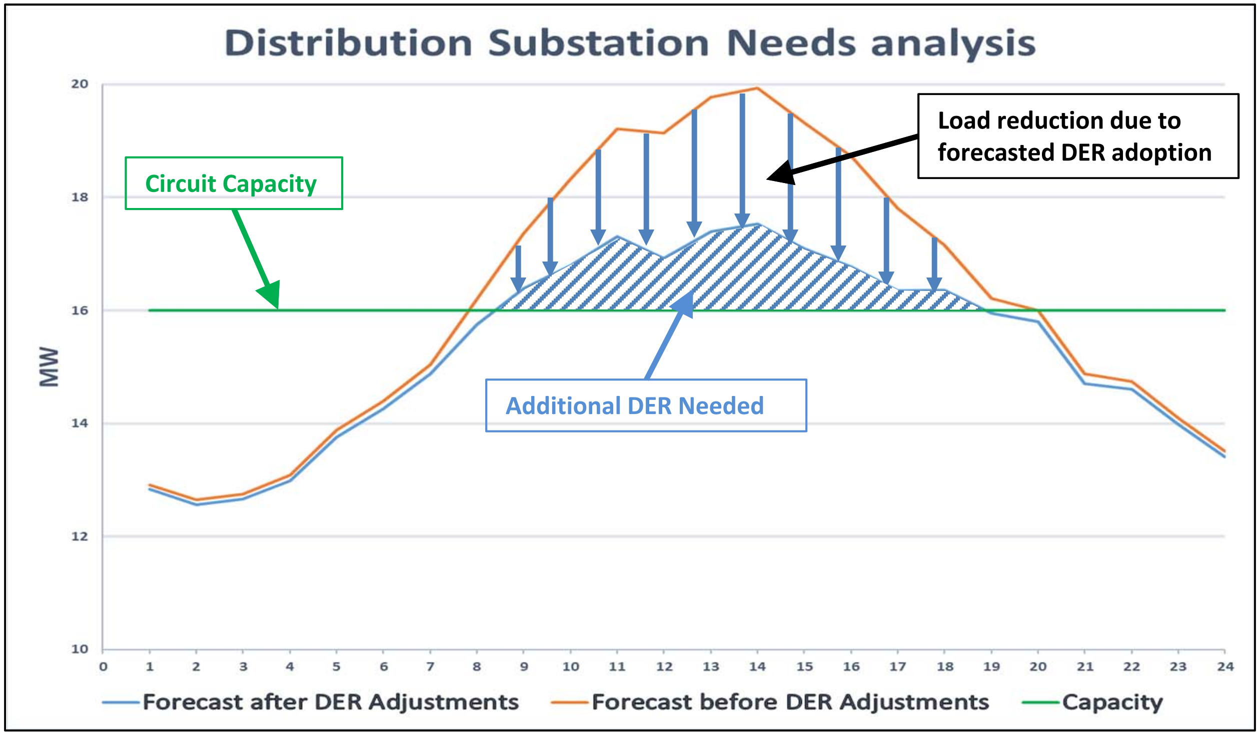
- The IDER pilot decision adopted a process that allows each of the Utilities to propose a method and to work with the Distribution Planning Advisory Group to finalize that method. Each utility may propose and utilize a different method for the adopted pilot. – page 21-22

# D. 16 12 036 on Double-Counting of Services (page 18-19)

In recognition of the solicitation principles adopted for the IDER pilot, the counting method to be used in the IDER pilot shall:

- 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.

# A Graphical Representation of the Issue




**Key Questions:**

Do existing utility planning assumptions provide a reasonable basis for assessing double counting?

What level of detail and certainty is associated with the DER assumptions used for planning?

**Forecasted DER Adoptions Include:**

- impacts of future energy efficiency programs , codes and standards
- impacts of future time dependent rates (load modifying demand response)
- impacts of future behind the meter distributed generation (primarily PV)
- impacts of future electric vehicle adoption

# Utility Proposed Incrementality Method(s)

- For purposes of this IDER pilot,  SDGE, PGE, and Edison are each planning to use, and modify accordingly, Incrementality Methodology #4.

- As mentioned in the CSFWG's Final Report, several parties expressed support for methods 4 and 5 explaining that criteria should be practical, simple, actionable, and encouraging of business.

- For the purposes of this IDER pilot, the Joint IOUs agree that Methodology #4 is most consistent with the guidelines and criteria provided by the Commission in D. 16 12 036.

- The Joint IOUs also agree that Methodology #5 is conceptually consistent with Methodology #4 and would like to explore with the DPAG any elements of Methodology #5 that could be added to Methodology #4 and implemented for the purposes of the IDER Incentive Pilots.

# CSFWG Incrementality/Double Counting Proposal #4 - Overview

| Tranche | Category | Description | Incremental |
|---|---|---|---|
| 1 | Not Already Sourced Through Another Channel | New technology or service that is not already being sourced or reasonably expected to be sourced through another solicitation, program or tariff that meets the identified distribution need. | Yes |
| 2 | Partially Sourced Through Another Channel | Existing technology or service that meets the identified distribution needs but at least some component of that technology or service is already begin sourced through another solicitation, program or tariff. | Yes, but only the portion (if any) that is not currently being sourced or can reasonably be expected to be sourced through another solicitation, program or tariff with the same locational and temporal granularity and performance guarantees as the bid technology. |
| 3 | Wholly Sourced Through an Another Channel | Everything not covered by Tranche 1 or 2, above | No, Technology is already being sourced or is reasonably expected to be sourced through another solicitation, program or tariff with the same locational and temporal granularity and performance guarantees as the bid technology |

# CSFWG Incrementality/Double Counting Proposal #4 – Tranche 1

| Tranche | Category | Example Bid | Incremental? |
|---|---|---|---|
| 1 | Not Already Sourced Through Another Channel | An "add-on" services to any already deployed DER that would allow that already deployed DER to provide the distribution service(s) solicited for. (for example a demand response program that utilizes existing communicating thermostats, DG, energy storage or electric vehicles)<br><br>A new load modifying demand response service that provides the local distribution service solicited for. (for example an appliance DLC program)<br><br>An energy efficiency technology or service that is not already included in the IOUs energy efficiency program portfolio. | Yes, if the existing resources without the "add on" were not capable of providing the distribution service they would not be included in the DER assumptions used for planning. |

# CSFWG Incrementality/Double Counting Proposal #4 – Tranche 2

| Tranche | Category | Example Bid | Incremental? |
|---|---|---|---|
| 2 | Partially Sourced Through Another Channel | Vendor bids in to deploy a combined new rooftop solar and energy storage system that provides the service being solicited for. | Yes, but only the portion (if any) that is not currently being compensated for by the existing base program or tariff, in this case the rooftop solar if compensated under NEM and/or the energy storage if compensated by SGIP or another program.<br><br>There would be a high bar in this case for the vendor to provide in their bid an M&V plan that would allow the IOU to substantiate for settlement purposes that the enhanced incentives had actually increased uptake of the resource in the local area in a way that did provide the distribution service(s) for which the vendor is seeking compensation. |

# CSFWG Incrementality/Double Counting Proposal #4 – Tranche 3

| Tranche | Category | Example Bid | Incremental? |
|---|---|---|---|
| 3 | Wholly Sourced Through Another Channel | Vendor submits bid for rooftop PV that is already compensated under NEM tariff without material enhancement justifying additional compensation.<br><br>Vendor submits bid for DG or ES that is already compensated under SGIP without material enhancement justifying additional compensation<br><br>Vendor submits bid for EE or DR service that is already in the IOU EE or DR program portfolio without material enhancement justifying additional compensation | No, distribution services provided have already been compensated for under existing programs or tariffs and those services have already been counted in the DER projections used for distribution planning. |

# CSFWG Incrementality/Double Counting Proposal #5

| | |
|---|---|
| **A** | When the attributes of DER resources have not been "sourced" through other mechanisms (*e.g.*, tariffs, programs, other competitive solicitations) they will be considered incremental. For example, if an EE project is not funded through programs (and not counted toward utility goals) it will be eligible to bid. In addition, existing resources can bid in attributes that were not paid for through other sourcing mechanisms. For example, rooftop PV may be supported by the NEM tariff or other incentives, but if their smart inverter capabilities were not "sourced" as part of that tariff they can be bid in to a competitive solicitation and receive an additional payment for the additional attribute offered. **Or if additional PV is built above and beyond what was forecast by the distribution planner.** |
| | |
| B | When the attributes of DER resources have been sourced at least partially using other mechanisms (*e.g.*, tariffs, programs, other competitive solicitations) at least a portion of those resources (to be determined) may be considered incremental if the bidder is able to demonstrate increased market participation due to the combined incentives. There are a number of ways this could work, for example the Brooklyn-Queens Demand Management example of combined incentives discussed at the July 14 CSFWG meeting, or a bidder is able to provide uptake that exceeds the expected market penetration that has been forecasted. The "burden of proof" for incrementality would be higher here than for A, and may require a set of examples where combining sourcing mechanism may be acceptable, as well as a case-by-case review in some situations at least in the beginning. |

# NRDC Questions

- How will specifications around incrementality be defined in a solicitation? (i.e. need to understand the specific language that will be use to guide and inform bidders) How will they be enforced?

- How can incrementality be addressed on a “technology neutral” basis? Can counting methods be developed based on existing (technology specific) incentives?

- How should incremental DER deployments that are caused by targeted or increased incentives be estimated?

AAdvice 5096-E

June 16, 2017

**Attachment E**

Distribution Planning Advisory Group Meeting #5 – April 6, 2017

# IDER Incentive Pilots – DPAG Meeting #5

## Candidate Project Selection & Prioritization

April 06, 2017


1

# IDER Incentive Pilot Candidate Projects

## Non-Market Sensitive Confidential Materials

- Location
- In-Service Date
- Distribution Service Provided
- Timing Certainty
- Market Certainty

## Market Sensitive Confidential Materials

- Project Financials

# Applying the Initial DIDF Screens

| Screen Applied | # of Projects | Distribution Service |
|---|---|---|
| | 40 Projects | Complete list of substation capacity projects 2017 to 2027 |
| Project Timing Screen | 10 Projects | Screens for projects with in-service dates of  June 2020 or later.  Assuming contracts are approved in July/August 2018 projects with in-service dates prior to June 2020 would have very limited time to fully deploy. |
| Project Services Screen | 9 Projects | Screens for projects that deliver one of four identified distribution services: 1.) distribution capacity; 2.) distribution voltage support; 3.) distribution reliability (back-tie) or 4.) distribution resiliency (micro-grid) |

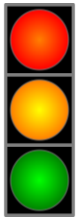
[redacted]

# The Candidate Projects

| Location | In-Service Date | Description |
|---|---|---|
| Project X | June 2020 | Install X bank 2 |
| Chowchilla | June 2020 | Replace El Nido bank 1 |
| Santa Rosa | March 2022 | Replace Rincon bank 1 or 2 with 30 MVA bank |
| Santa Nella | May 2022 | Replace Santa Nella bank 1 and install 12 kV feeder |
| San Jose | May 2022 | Replace Llagas bank 2 w/ 45 MVA or install new 45 MVA at new Spring Sub (Transmission) |
| Madera | June 2023 | Install 1-12 kV feeder - Storey bank 1 |
| Bakersfield | June 2027 | Gosford Substation:  construct new substation |
| Paso Robles | June 2027 | Estrella Substation: construct new substation |
| Roseville | June 2027 | Athens Substation: construct new substation |

# The Candidate Projects Prioritization

## Project Prioritization Metrics



### Certainty

**Metrics:**

- Is load driven by large request from individual customer or by more distributed growth on the circuit/bank? (single customer -- distributed growth)
- What is the size of the projected overload in MW and % of normal operating capacity? (small – large)
- How far in the future is the need? (far – near)

### Market

**Metrics:**

- Is load driven by large request from individual customer or by more distributed growth on the circuit? (single customer -- distributed growth)
- What is the size of the projected overload in MW relative to the customer population and the total load on the circuit/bank? (large -- small)
- How far in the future is the need? (near – far)

### Overall

**Metrics:**

- If certainty is red then overall is red.
- If certainty is amber then overall is amber.
- If certainty and market are both green then overall is green.
- All other combinations are amber.

# The Candidate Projects Prioritization

## Chowchilla & San Jose Projects


**The Chowchilla (June 2020)** project to replace El Nido bank is currently proposed for a DER mitigation via DRP Demonstration Project C.

**The San Jose (May 2022)** project to replace Llagas bank 2 w/ 45 MVA or install new 45 MVA at new Spring Sub (Transmission) is reviewing bids under the 2016 energy storage RFO.

# The Candidate Projects Prioritization

## Project X


**X (June 2020)** project is driven by new business request from a single large customer on the circuit. PG&E is currently working with the customer to confirm the size and timing of the requested load increase and to determine if alternative engineering or operating solutions could mitigate the projected overloading issues all or in part.

If PG&E and customer agree to move forward with the project as described in the project description, based on the size and the timing of the need, there would be limited opportunity to solicit a DER alternative via the CSF prescribed for IDER Incentive Pilots in D 16 12 036.

# The Candidate Projects Prioritization

## Santa Nella, Madera, Bakersfield, Paso Robles and Roseville Projects


**The Santa Nella (May 2022) and Madera (June 2023)** project are all driven by very small projected overloading (less than 5% of normal circuit operating capacity at the 90$^{th}$ percentile load projection). As such the project timing certainty is low, PG&E will re-assess the need, timing and scope for the projects in the 2017/2018 planning cycle.

**The Bakersfield, Paso Robles and Roseville (all June 2027)**substation project timing is also very uncertain at this time. These project are on our 10-year plan project list only because of the need to identify the project in order for PG&E's Land Department to begin investigating local zoning, rights of ways and permitting issues in the area.

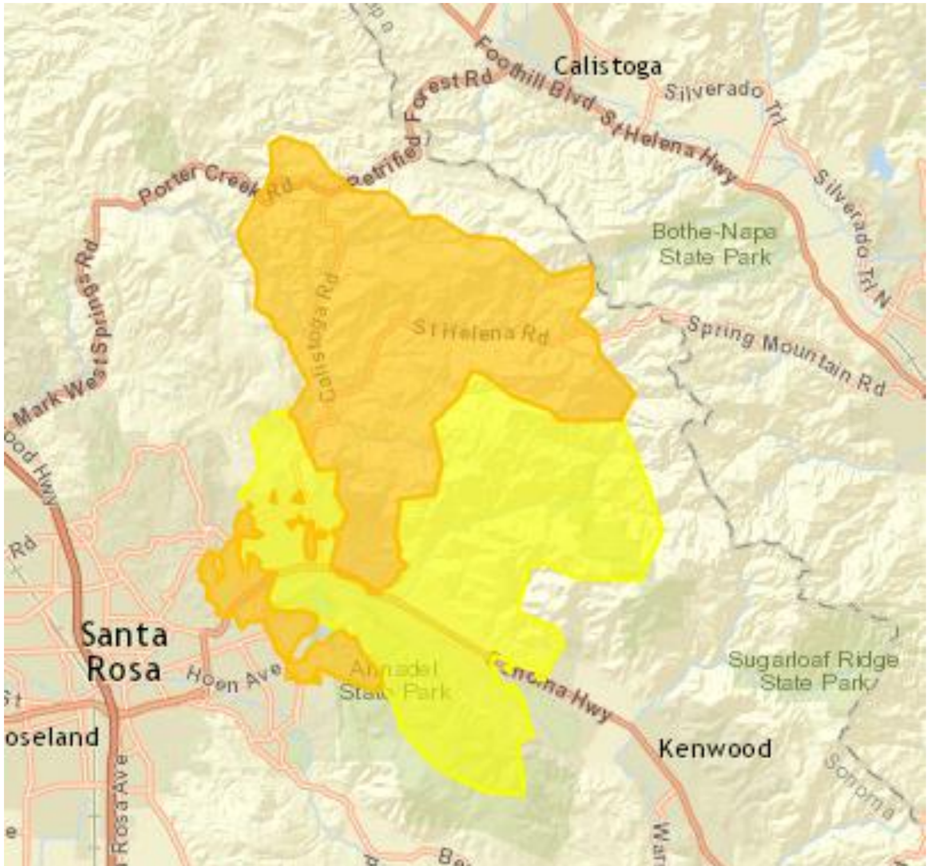
# The Candidate Projects Prioritization

## Santa Rosa Project


**The Santa Rosa (March 2022)** project to upgrade one of the current Rincon substation 16 MVA banks to a 30 MVA bank Rincon substation may have the ideal mix of attributes for the IDER Incentive Pilot. The project timing relative certain based on confidence in the load projections. The projected load reductions needed for deferral are in the range of 2MW-3MW which makes the market feasibility relative high given the customer base in the area is diversified with a mix of residential, SMB as well as some medium and large commercial customers including schools and hospitals.

The timing, frequency and duration of the projected overloading may be attractive for a range of DER based mitigations.

# PG&E's Proposed IDER Incentive Pilot
# Santa Rosa – Rincon Substation Project




Rincon Substation serves customers in northeast Santa Rosa primarily along the Sonoma Highway (CA 12) and Calistoga Road corridors.

**Diversified Customer Base**
13,344 residential customers
569 SMB customers
179 LCl customers

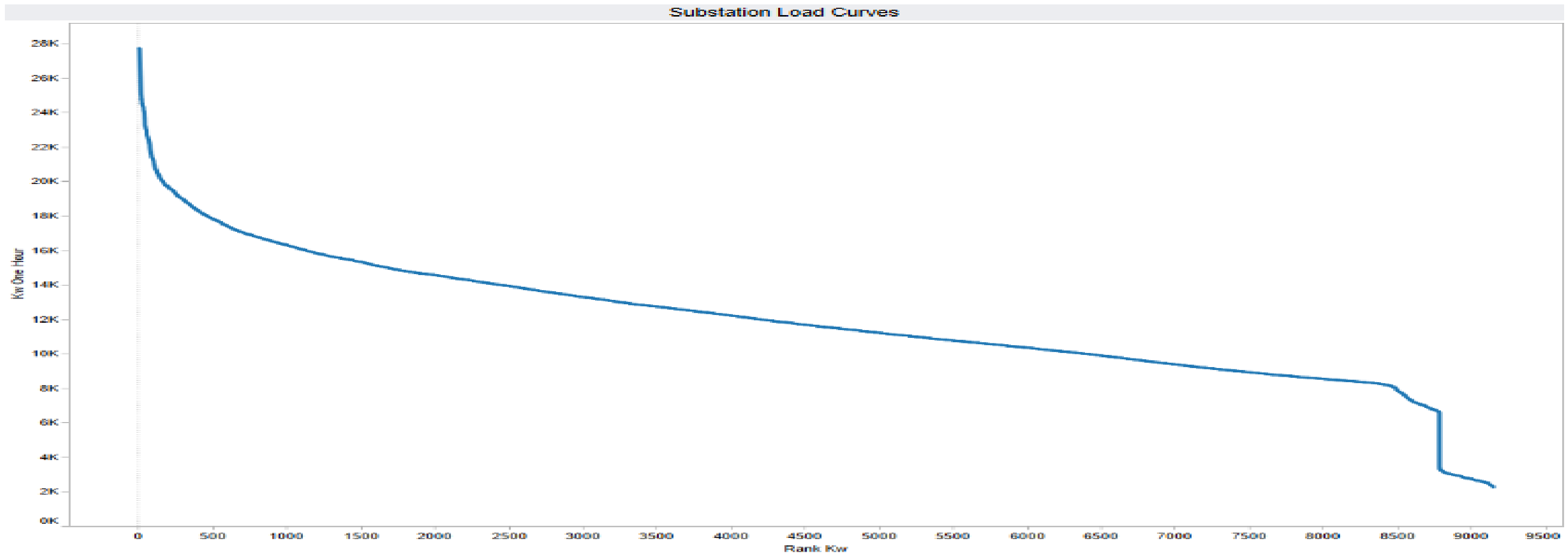
| | |
|---|---|
| **Currently Installed DG** 792 Installed systems 4.7 installed MW | No **Energy Storage** Installed (per interconnection reports) |

637 **SmartAC** Direct Load Control Customers, X LCI DR program Customers

**Projected 2022 load** (90th percentile) ~ 34 MW (non-coincident peak on both banks)
Normal operating capacity of ~ 32 MW (each bank has a normal operating capacity of 15.84 MW

[redacted]

# PG&E's Proposed IDER Incentive Pilot
# Santa Rosa – Rincon Substation Project
## (Based on Recorded Values March 2016 – February 2017)




**Substation Name**

RINCON

**Load Hours for Heat Map**

Enter Top X Hours: 50

Summer Peaking Between 4:00 PM-9:00 PM

**Count of Seasonal and Hourly Occurance of Top 50 Load Hours for RINCON Substation**

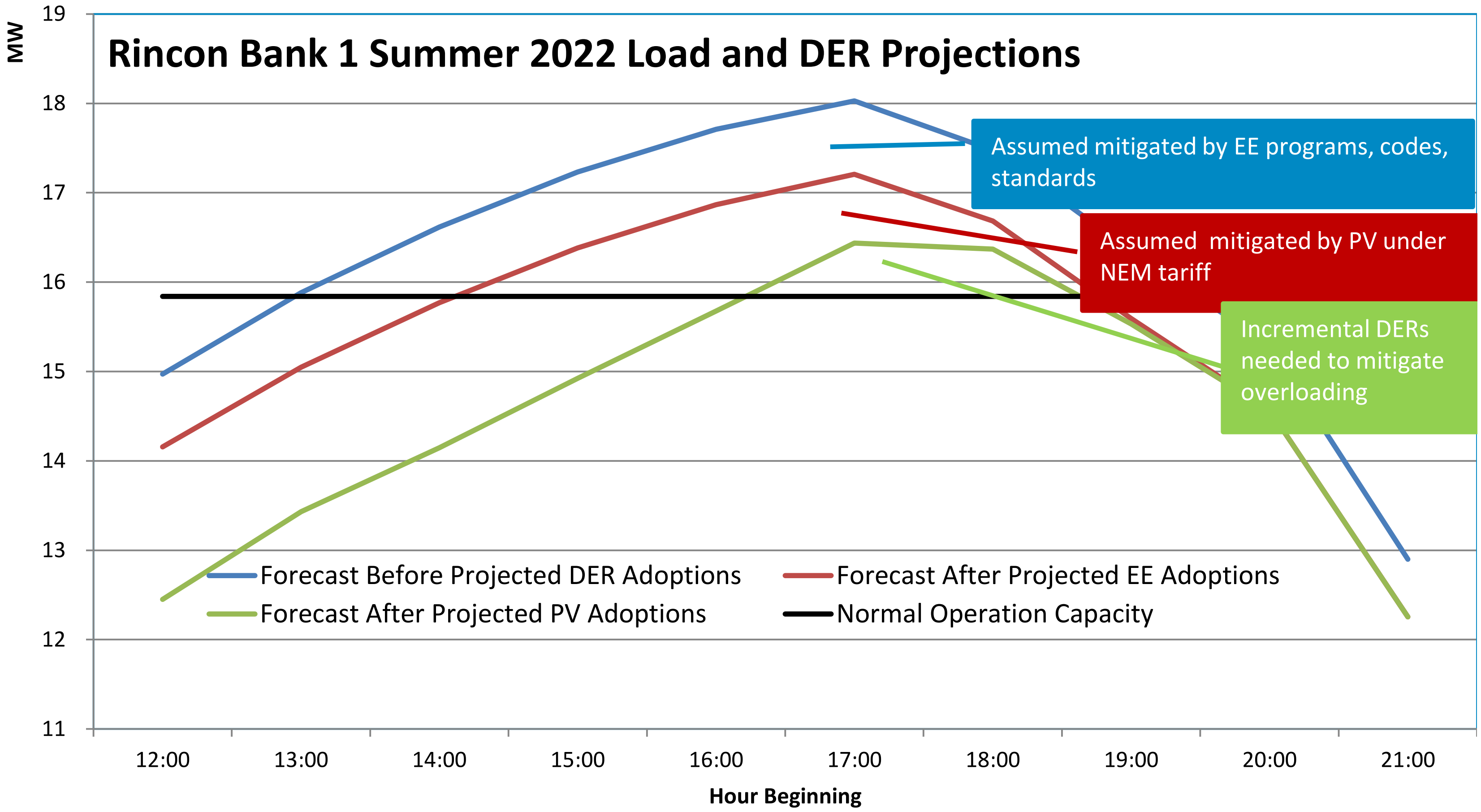
Hour Ending

| | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| January | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| February | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| March | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| April | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| May | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| June | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 3 | 5 | 2 | 1 | 0 | 0 | 0 |
| July | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4 | 6 | 7 | 3 | 1 | 0 | 0 | 0 |
| August | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| September | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 3 | 5 | 4 | 4 | 0 | 0 | 0 | 0 |
| October | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| November | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| December | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Count of Seasonal and Hourly Occurance of Top 50 Load Hours for Feeders at RINCON Substation**

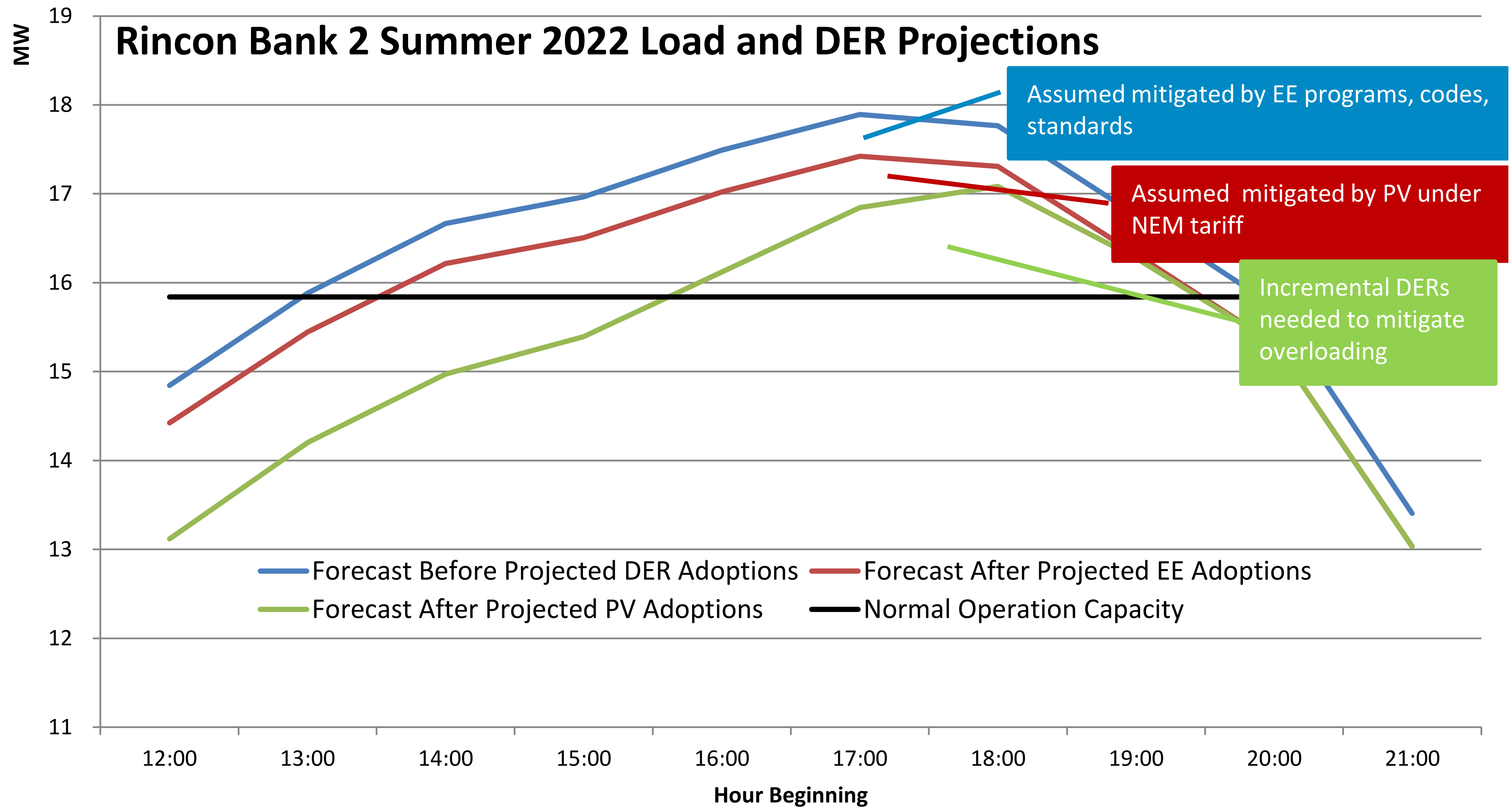
[redacted]

# PG&E's Proposed IDER Incentive Pilot
# Santa Rosa – Rincon Substation Project




[redacted]

# PG&E's Proposed IDER Incentive Pilot
# Santa Rosa – Rincon Substation Project




[redacted]

# Distribution Services Needed

**Illustrative Minimum Resource Attributes Needed**

**For DPAG Discussion Purposes Only**

**Service:** Distribution capacity
- Reduce in-area load
- Increase in-area generation

**Timing:** June - October, all day types, 4:00 pm to 9:00 pm

**Frequency:** 6-9 days total during June - October

**Duration:** 2-5 consecutive hours per day, 3 consecutive days

**Dispatch:** Day ahead notification

**Amount:** 250KW -500 KW per bid (2MW-3MW total)

**Length:** 3 years to 10 years

[redacted]

# Questions and Closing

Questions?

Next Meeting

- Contingency Planning
- Double Counting Discussion Continued
- Anything from today that needs further clarification

Advice 5096-E

June 16, 2017

# Attachment F

Distribution Planning Advisory Group Meeting #6 – April 13, 2017

# IDER Incentive Pilots DPAG Meeting # 6

## Contingency Planning
## +
## Double Counting/Double Payment Part II

**April 13, 2017**

# Meeting Agenda

| | |
|---|---|
| Safety Message, Meeting Protocols, and Roll Call | 10:00 - 10:15 |
| Background: D. 16-12-036 on Contingency Planning | 10:15 - 10:20 |
| Contingency Planning Presentation and Discussion | 10:20 - 11:45 |
| Lunch | 11:45 - 1:00 |
| Recap on Double Counting/Double Payment from Meeting #4 | 1:00 - 1:20 |
| CEEIC Proposed Method and Discussion | 1:20 - 2:00 |
| Next Steps and Preview of Meeting #7 | 2:00 - 2:15 |

# IDER Contingency Planning

- D. 16-12-036 states, "A contingency plan should be developed by the Utilities in consultation with the Distribution Planning Advisory Group for the purposes of the pilot"
- Per D. 16-12-036, "A contingency plan provides the utility procuring the distribution service an option if the distributed energy resource being procured proves unviable"
- Several scenarios may occur during the DER solicitation, DER deployment or DER commercial operation that may require the IOUs to implement a contingency plan.
- Some contingency solutions have the potential to impact total cost of the solution and deferral benefit

# IDER Contingency Planning

| Scenario | Contingency Options/Priority |
|---|---|
| **DER Solicitation**<br>No cost-effective DER bids or combination of cost-effective DER bids meet the distribution needs; or contracts not approved by CPUC | 1. Build traditional project intended for deferral |
| **DER Implementation**<br>DER provider(s) is unable to install DER according to bid | 1. Pursue construction of traditional project intended for deferral<br>2. Develop short lead time mitigation alternatives where feasible |
| **DER Commercial Operation**<br>DER fails during commissioning, or underperform during operations (based on commissioning and performance verification protocols agreed to in the contract) | 1. Determine emergency limitations if applicable and work with system operations on potential temporary grid reconfiguration or load drop (for all scenarios)<br>2. Determine reason for DER underperformance<br>3. Assess if new mitigation is required and determine expedited solution options |

# IDER Contingency Planning Decision Priority

**Procure DER**

- Procure DER to meet distribution needs
- If initial DER solicitation doesn't meet needs, pursue traditional project or short lead time mitigation alternatives

**Alternative Mitigation Solutions**

- Develop/Install short lead time mitigation alternatives where feasible
- Install original solution intended for deferral

**Perform Emergency Grid Operations**

- Initiate emergency contingency if applicable
- Determine reason for DER not performing
- Determine if mitigation solutions are required

# IDER Contingency Planning Considerations

- Contingency solutions depend on timing of distribution need and lead time to implement those solutions

- Distribution Planning must work with Distribution System Operations to determine response if DER underperformance leads to emergency conditions

- Grid monitoring, sensing, testing and communication equipment may be required to optimize DER performance and/or verify that DER is performing according to contract terms and meeting distribution needs


Please return promptly at 1:00 to continue discussion of double counting/double payment from DPAG meeting #4

# Recap of Meeting #4 Discussion on Double Counting/Double Payment

## D. 16-12-036 on Double Counting/Double Payment

In recognition of the solicitation principles adopted for the IDER pilot, the counting method to be used in the IDER pilot shall:

- 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

# Utility Proposed Incrementality Method(s)

- For purposes of this IDER pilot, SDGE, PGE, and SCE are each planning to use, and modify accordingly, Incrementality Methodology #4

- As mentioned in the CSFWG's Final Report, several parties expressed support for methods 4 and 5 explaining that criteria should be practical, simple, actionable, and encouraging of business

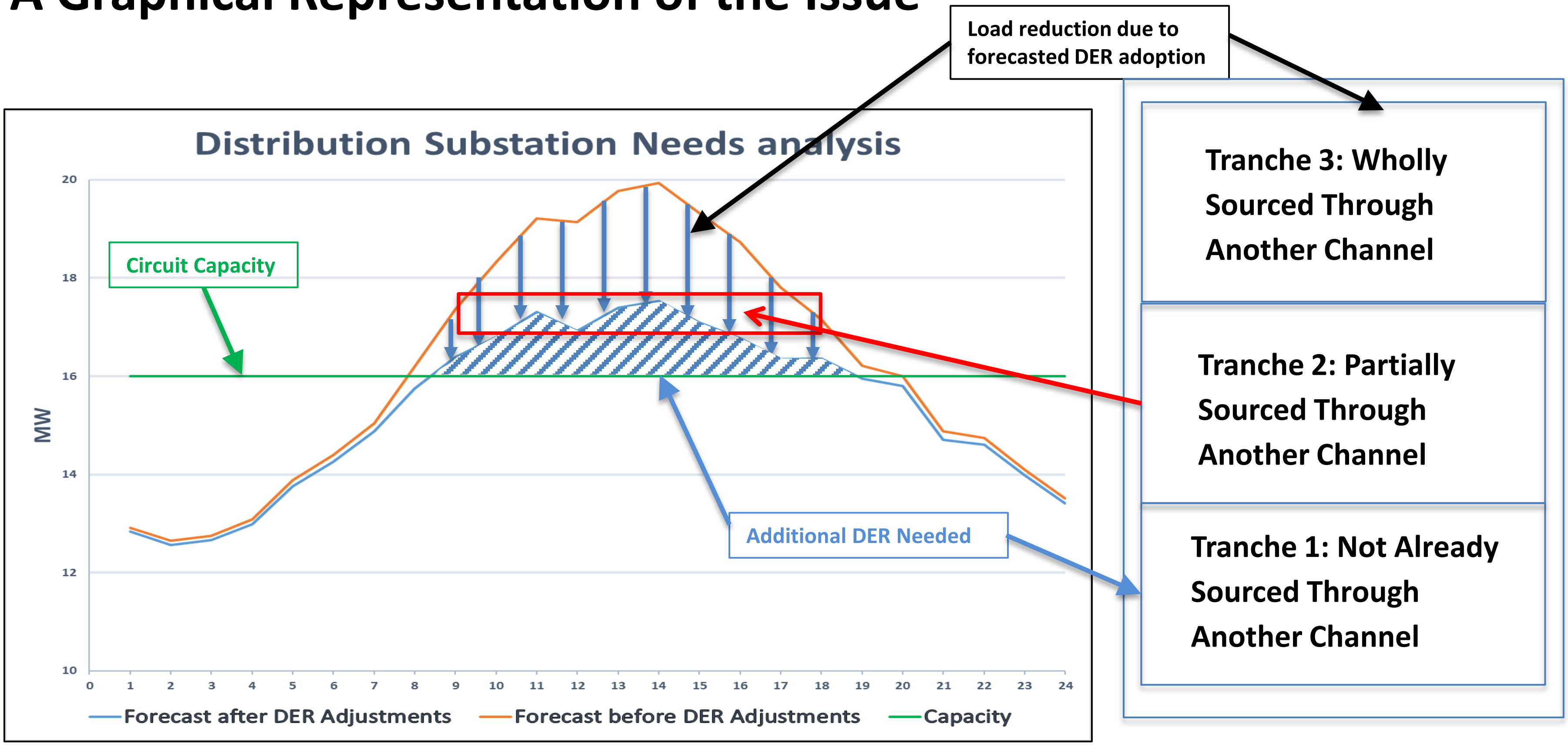
- For the purposes of this IDER pilot, the Joint IOUs agree that Methodology #4 is most consistent with the guidelines and criteria provided by the Commission in D. 16-12-036

- The Joint IOUs also agree that Methodology #5 is conceptually consistent with Methodology #4 and would like to explore with the DPAG any elements of Methodology #5 that could be added to Methodology #4 and implemented for the purposes of the IDER Incentive Pilots

# CSFWG Incrementality/Double Counting Proposal #4 - Overview

| Tranche | Category | Description | Incremental |
|---|---|---|---|
| 1 | Not Already Sourced Through Another Channel | New technology or service that is not already being sourced or reasonably expected to be sourced through another solicitation, program or tariff that meets the identified distribution need. | Yes |
| 2 | Partially Sourced Through Another Channel | Existing technology or service that meets the identified distribution needs but at least some component of that technology or service is already begin sourced through another solicitation, program or tariff. | Yes, but only the portion (if any) that is not currently being sourced or can reasonably be expected to be sourced through another solicitation, program or tariff with the same locational and temporal granularity and performance guarantees as the bid technology. |
| 3 | Wholly Sourced Through an Another Channel | Everything not covered by Tranche 1 or 2, above | No, Technology is already being sourced or is reasonably expected to be sourced through another solicitation, program or tariff with the same locational and temporal granularity and performance guarantees as the bid technology |

# A Graphical Representation of the Issue




**Forecasted DER Adoptions Include:**

- impacts of future energy efficiency programs , codes and standards
- impacts of future time dependent rates (load modifying demand response)
- impacts of future behind the meter distributed generation (primarily PV)
- impacts of future electric vehicle adoption

*Illustrative Only – Not to Scale*

# Joint IOU Commitment to Perspective Bidders

Based on feedback and discussion with DPAG participants during and after DPAG Meeting #4:

- IOU's will be as specific as possible in the RFO materials regarding assessment of incrementality per CSFWG Proposed Method #4.

- IOU's will work with their IDER Incentive Pilot Independent Evaluator (IE) to assess the feasibility of increased pre-bid submittal communication and/or guidelines regarding incrementality assessments.

# CEEIC Proposal

Next Steps

Preview of DPAG Meeting #7

Advice 5096-E

June 16, 2017

# Attachment G

California Efficiency + Demand Management Council (CEEDMC, formerly CEEIC) Presentation

California Energy Efficiency Industry Council

# Another Approach to Incrementality: Forecast Overlap Factor

**DPAG Meeting #6**

**April 13, 2017**

California Energy Efficiency Industry Council

*Moving Efficiency Forward*

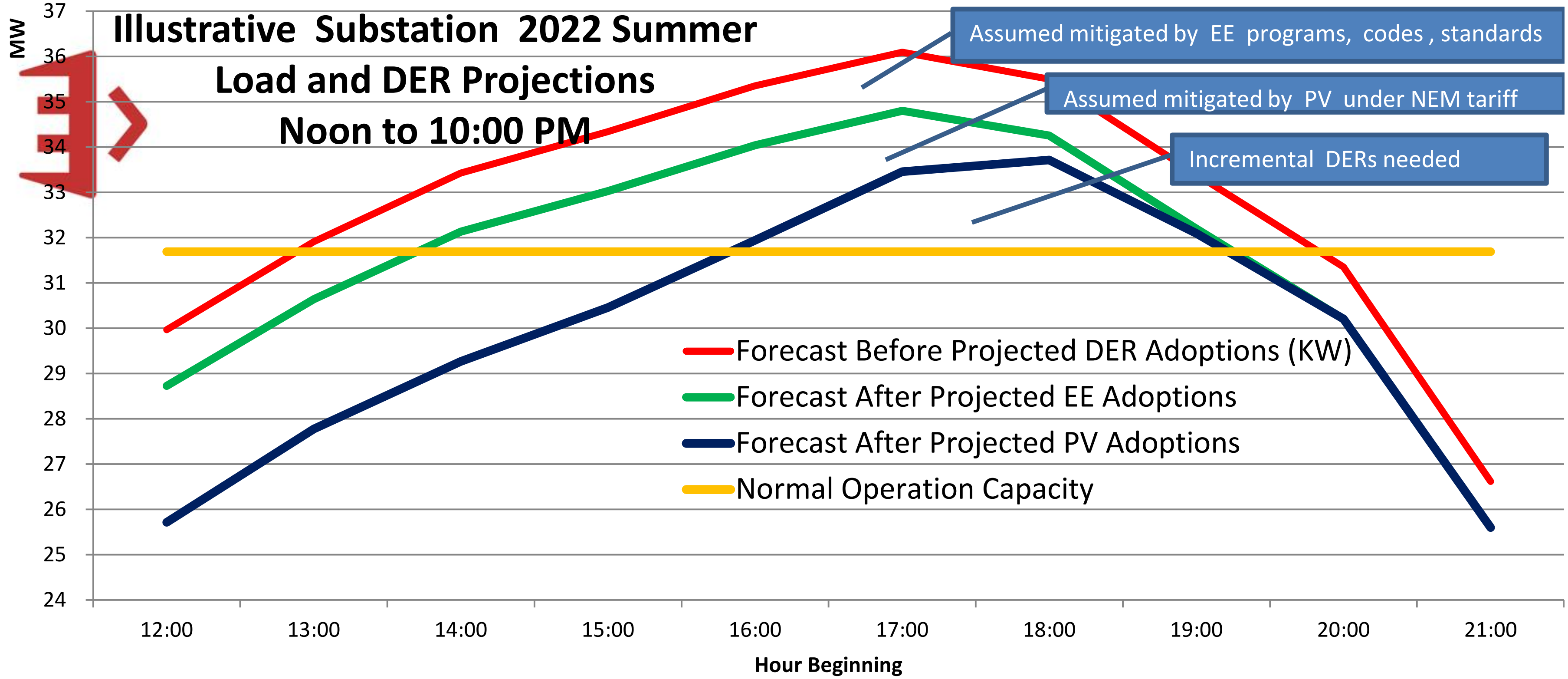
# Alternative Simple Method

- Provides a means to objectively quantify the incrementality of potential offers and their subcomponents
- Is congruent with planning assumptions
- Is consistent with Incrementality Methodologies #4/5 proposed by IOUs
- Is an optional method. Each bidder can choose which approach to take

*Moving Efficiency Forward*

# Method Overview

- Calculate a “forecast overlap factor”
- Use factor to separate offer benefits into two components:
  - Portion that corresponds to the incremental DERs required to meet the distribution need
  - Portion that corresponds to the forecasted DERs included in the distribution plan
- Improves with planning detail and certainty




| 18:00 | |
|---|---|
| Forecast before DER Adoptions | 35,500 kW |
| Forecasted DERs | 1,800 kW |
| EE (Total) | 1,250 kW |
| EE from Programs (50%) | 625 kW |
| DR | 20 kW |
| PV | 530 kW |
| ES | 0 kW |
| Forecast after DER Adoptions | 33,700 kW |
| Normal Operation Capacity | 31,700 kW |
| Incremental DERs Needed | 2,000 kW |

| 18:00 | |
|---|---|
| EE Forecast Overlap Factor | 16.5% |
| DR Forecast Overlap Factor | 0.5% |
| PV Forecast Overlap Factor | 14.0% |
| ES Forecast Overlap Factor | 0% |

*Moving Efficiency Forward*

# Example: EE Offer Components

- EE offer would have two components:
  - 83% - Portion required to meet the incremental distribution need
  - 17% - Portion required to cover the overlap with EE embedded in the forecast
- For offers that include multiple DERs with differing planning assumptions, appropriate factors would be applied to each DER

# Requirements for Method to Work

- Planning assumptions for EE and other DERs must be suitably detailed and accurate. Planning values need to be provided for differing technologies and delivery mechanisms (e.g. EE upstream, downstream, and C&S)
- Bidders are provided with mechanism to get paid for the portion of their offer that contributes to forecasted EE (and other DERs)

# Questions?

## Thank you!

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Advice 5096-E

June 16, 2017

**Attachment H**

Independent Professional Engineer Presentation #1

(Introduction and General Topics)

April 20, 2017

# IDER Pilot: IPE DPAG Presentation

## Introduction and General Topics

Nexant
Reimagine tomorrow.

April 20, 2017

# Agenda

- Introduction
  - DPAG#2 Candidate Screening
  - Timing Considerations
  - Miscellaneous
- Contingency Planning
- Incrementality
- Review of IOU Project Selections
  - SDG&E Specific Materials
  - SCE Specific Materials
  - PG&E Specific Materials

(Three separate PPTs & three separate sessions)

# Introduction

DPAG #2 Project Screening and Prioritization

# IDER Incentive Pilot Project Screening – DPAG #2

- Overall approach reviewed by IOUs to identify:
  - Which planned projects are **good candidate projects**
  - How to **prioritize** these projects to arrive at the final proposed pilot projects

- Good candidate project screen
  - Intent – to identify the most likely successful projects
  - Candidates include
    - DER service screen
    - Project timing screen

*- More details in the next slide……*

# Good Candidate Project Screen – DPAG#2

- DER service screen - Potential services included
  - Distribution capacity
  - Voltage support
  - Reliability service (Back-tie)
  - Resiliency service (micro-grid)

- Project timing screen
  - Required operational date of **2020 or later**
  - Considered as candidates for DER deferral under IDER Incentive Pilot

# Priority Screen

- Review each candidate project for:
  - DER attribute requirements
    - Determine the amount of DER/portfolios required for distribution services
  - Project timing certainty
    - Determine the certainty of project in-service date
  - Financial assessment
    - Assess DER attribute requirements vs. wire alternatives
  - Market assessment
    - Assess the number and composition of customers in each project area
    - Determine the ability of BTM DER solutions to meet identified needs

# Introduction

Timing Considerations

# IDER Pilot Project Timing – From CPUC Decision

- June 16, 2017 ➢ Utilities file proposed projects after DPAG advice
- Oct 16, 2017 ➢ CPUC to approve filings

- May 16, 2017 ➢ Utilities complete procurement and file with CPUC
- Aug 16, 2018 ➢ CPUC approves procurement (approx. date)

- Sept 1, 2018 ➢ Utilities execute contracts with DER providers

# Background - Project Timing

- Considerations:
  - Utility projects normally needed to address summer peak (June 1)
  - IDER Pilot timing eliminates projects in June 2017 & 2018
  - DER developers have about a maximum of 8-10 months to complete development of June 1, 2019 projects
  - Could require a month of that time to verify operation of DERs
  - Could be delayed if steps take longer than planned

- Observations:
  - 2019 a very aggressive schedule
  - Not likely to lead to a successful pilot
  - Likely biased toward some technologies/project types
  - Potentially increases contingency costs
    - Traditional project costs related to procurement and construction grow rapidly during the last 12 months prior to June 1
  - June 2020 and later projects are much more likely to be successful

# Contingency Planning

# Utilities Thoughts - Three Time Frames – DPAG #6

- DER Solicitation Period contingency
  - Propose to build planned project
- DER Implementation Period contingency prior to commercial operation
  - Propose to build planned project, or develop short lead time alternative
- DER Commercial Operation contingency
  - If emergency work with operations to develop emergency work around if possible or plan to drop customer load
  - Determine root cause of DER failure, assess options to remedy and then expedite solution

# DER Implementation Period Contingency

Discussions/Observations/Recommendation

- Options to address contingency will vary
  - Vary with time of contingency (early vs later) and total number of DERs selected
  - Exposure covers a period of 2 to 3+ years depending upon project date
  - Many things can happen during that period

- Recommend to evaluate options based upon the facts at the time
  - Select the least cost alternative fully considering DERs and contingency costs
  - Not possible to prescribe the best choice ahead of time

- Contingency Planning is more a process than a defined single contingency plan – recommend developing process and guidelines if more certainty needed

- Some long lead time items may require up to 12 months to procure and install so the shorter this period is the potentially larger the cost of maintaining a viable traditional project as a backup

# DER Implementation Period Contingency, continued

- Projects with later year of need (i.e. 2022)
  - Could consider bringing project or parts of the project in ahead of June 1
  - Reduce risk and cost of a contingency planning
    - Keeping a traditional project viable is most costly during the last 12 months
    - Addressing forecast error that results in faster load growth than forecasted

- Concept of procuring “reserve” DER capability merits consideration
  - To address failure of one DER component
    - Where there are many DERs procured in a portfolio
  - Or, to address the potential for slower than projected DER growth
    - Which would result in a larger need on June 1 than forecast
  - Costs could be considered for treatment as part of a startup effort

# DER Commercial Operation Contingency

Discussions/Observations/Recommendation

- Important to find out contingency exists as early as possible
  - Periodic demonstrations are critical to achieving this early detection – similar to CAISO Ancillary Service Testing (i.e. Black Start type testing)
  - Installation of needed meters and measurements are also critical to early detection
  - These are operating functions, not financial, so information processing must be timed to meet operating needs in addition to settlement needs

- Early detection of contingency
  - Allows for more options to be considered, and
  - Limits need to find solutions in an emergency environment
    - i.e. week of or day before the event

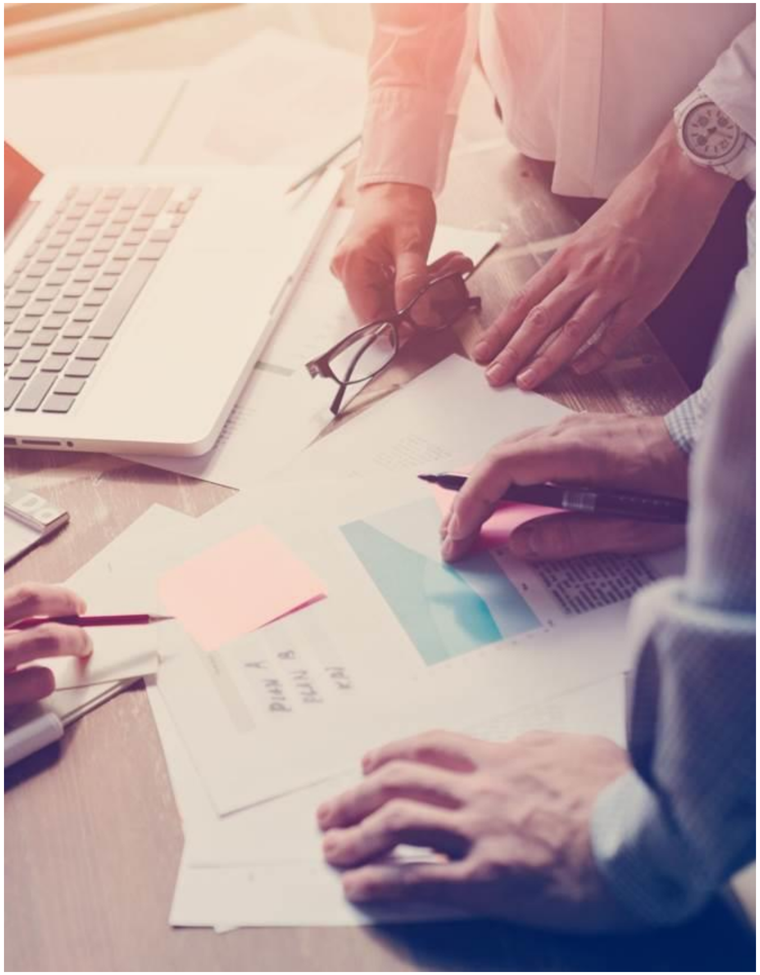
- In the end, must work with operations and develop customer emergency plan/outage rotation plan (smaller scale but same function as CAISO plans)

Reimagine tomorrow.

# Incrementality

# Incrementality - DPAG #6

- Utilities have proposed Method 4 with potential to add Method 5
  - Propose to be as specific as possible in RFO materials
  - Work with IDER (IE) to assess feasibility of pre-bid information and guidance
  - Ultimate determination performed by utility after the bid
  - Indicated that they intend to be liberal in application of the rules and error on the side of inclusiveness of bidders



# Incrementality - DPAG #6

| Tranche | Category | Description | Incremental |
|---|---|---|---|
| 1 | Not Already Sourced Through Another Channel | New technology or service that is not already being sourced or reasonably expected to be sourced through another solicitation, program or tariff that meets the identified distribution need. | Yes |
| 2 | Partially Sourced Through Another Channel | Existing technology or service that meets the identified distribution needs but at least some component of that technology or service is already begin sourced through another solicitation, program or tariff. | Yes, but only the portion (if any) that is not currently being sourced or can reasonably be expected to be sourced through another solicitation, program or tariff with the same locational and temporal granularity and performance guarantees as the bid technology. |
| 3 | Wholly Sourced Through an Another Channel | Everything not covered by Tranche 1 or 2, above | No, Technology is already being sourced or is reasonably expected to be sourced through another solicitation, program or tariff with the same locational and temporal granularity and performance guarantees as the bid technology |

Source: IOU DPAG#6 Presentation April 13, 2017

# Discussion/Observations/Recommendations

Comments on the IOU proposal

- Complicated issues discussed in great detail in WG and not new
- Difficult to get one's arms around the complexities
- Good news?
  - Do not have to solve in the IDER Incentive Pilot
  - Long term solutions to be developed in IDER, DRP

- Apparent issue largest for EE bids
  - Good news it may diminish over time
  - As most future EE will likely be driven by codes and standards
  - Extent of the issue for EE bidders not known

- Method 4 Tranche 2, as written, seems to have the potential to consider all EE bids that are already "sourced" as not incremental
  - Not related to how much is in the DER forecast
  - Has the potential to reduce competition if bidders not certain of how it will be applied

# Discussion/Observations/Recommendations

General comments

- To promote full competition it is important for bidders to be able to determine if their approach/bid is going to be acceptable (Incremental) as early as possible in the process
- Best approach would be to allow bidders to do that before they are required to prepare a full bid (and incur the cost of preparing a full bid)
- At least two conceptual options exist
  - Self-determination by bidder based upon information provided by the utility
  - Utility determination

# Discussion/Observations/Recommendations

Two conceptual options (continued)

- Self-determination by bidder
  - May be certain if information provided by Utility is binding (i.e. CEEIC proposal or other approach)
  - May not be certain in the end if the information cannot be used to make a clear self-determination despite best efforts by the Utility

- Utility determination
  - Can be non-binding based upon a questionnaire submittal
  - Can be binding based upon a questionnaire submittal
  - Could be burdensome if many bidders respond and need Utility determination in a short period of time

# Discussion/Observations/Recommendations

A Possible Hybrid Approach

- Consider only for use in IDER Incentive Pilot and not setting a precedent for long term solutions being explored in the DRP and IDER proceedings
- Acknowledge that nothing is perfect, error on the side of inclusion/participation
- Utilities provide clear binding guidance on a program basis for the geographical areas in the pilot; this hopefully will address many of the bidders needs
- For special bids cannot be handled using the binding guidance, bidders would use a questionnaire to  provide information to utility who would make a binding determination
- Utilities have indicated they would be liberal in their interpretation of incrementality for the pilot in the interest of inclusiveness for the pilot
- Utilities should have ability to modify procured amount to address “overlap” in final DER portfolio

# Miscellaneous

Number of DER Contracts

# Number of DER Contracts

During DPAG #6  the three utilities indicated preference as to their approach to the number of contracts/counterparties they would want to use to procure needed DERs

- SDG&E indicated that they would want to contract with one individual
- SCE and PG&E indicated they would enter into a contract  with each winning bidder
- Pros and cons with both options
  - Very preliminary discussions follows……

# Number of DER Contracts

Single contract -

- Pros
  - Single entity is accountable for all DERs to meet the needed attributes
  - Easier to coordinate capture of built-in DER developer reserve in emergency or normal operation
  - Single control interface for controllable DERs for utility (Developer to provide for multiple interfaces as required)
  - Single settlement interface for utility (Developer to provide for multiple interfaces as required)
  - May Simplify evaluation of bids
- Cons
  - May require different technology vendors/companies to work together to develop cost and risk sharing agreements which can get complicated (assumes multiple technologies and developers in solution); may be required prior to initial bids,

    Or, may require a single large firm to act as master developer and investor
  - Could slow down timely development of DER bids due to complexity (multiple developers working together) which would serve to reduce number of bidders
  - Could reduce number of bidders assuming the single large master developer model
  - May complicate options in future procurement if more DER needed in future in same area?

# Number of DER Contracts

Contract with each winning bidder -

- Pros
  - Simpler and faster for individual developers to develop bids not having to work with other bidders/developers
  - Tend to increase number of DER bidders participating in the RFO process
  - Approach does not constrain future procurement
  - May provide better visibility to utility operations (depending upon the structure of agreement)
- Cons
  - Multiple control interfaces may be required for utility
  - Multiple settlement interfaces may be required for utility
  - More difficult to coordinate/capture built-in DER developer reserve in emergency or normal operation

# Comments / Questions


Q&A

Advice 5096-E

June 16, 2017

**Attachment I**

Independent Professional Engineer Presentation #2

(PG&E Pilot Project Selection)

April 20, 2017

# IDER Pilot: IPE DPAG Presentation

## PG&E Pilot Project Selection

Nexant
Reimagine tomorrow.

**April 20, 2017**

# Agenda

- Review of Pacific Gas and Electric  IDER Pilot Selection Process and Results

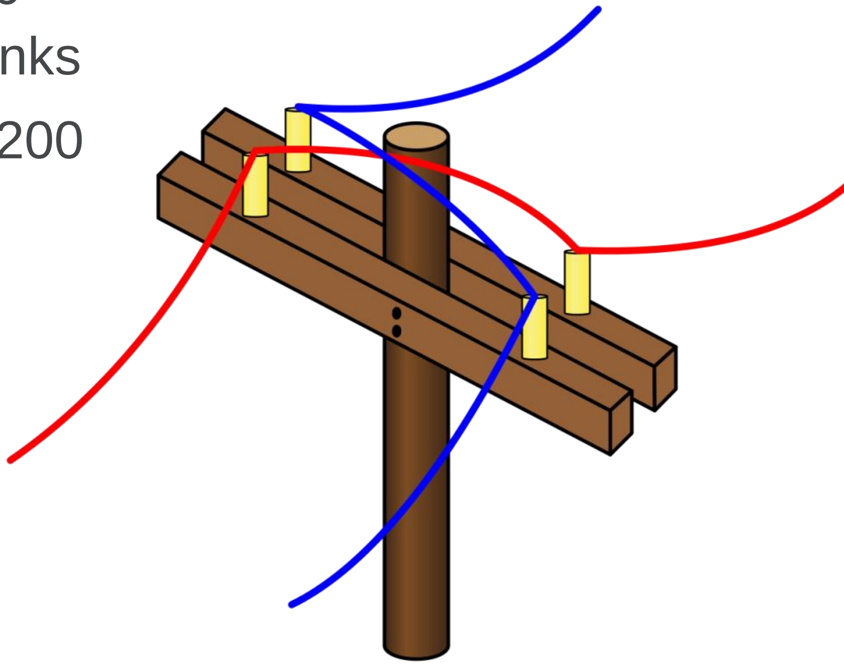
# PG&E Distribution System and Plan

Distribution System

- Utilize primarily 4kV, 12kV and 21 kV circuits with some minor 17kV and 34kV circuits
- Current Substation Count – about 800 substations with 1200 transformer banks
- Current Number of Circuits – about 3200

2016/2017 Distribution Plan

- Started screening process with 40 Planned Projects



# PG&E Screening Process and Results

- Included 40 Substation Projects in the 2017 to 2026 plan
- Then applied a June 1, 2020 and later timing screen
  - Resulted in 10 candidate projects
- Screened for four services identified in CPUC Decision
  - Resulted in 9 candidate projects
- Eliminated one project planned to meet reliability criteria
  - Criteria - No more than 6,000 customers per circuit under normal conditions
  - Project serves customers under normal conditions
  - Requires 10-15 MWs of capacity

# Nine Candidate Projects

- Projects needed in 2020 - 2 transformer bank projects
- Projects needed in 2022 - 3 transformer bank related projects
- Projects needed in 2023 - 1 bank and new feeder project
- Projects needed in 2027 - 3 potential new substation projects

# Nine Candidate Projects

| Location | In-Service Date | Description |
|---|---|---|
| Project X | June 2020 | Install X bank 2 |
| Chowchilla | June 2020 | Replace El Nido bank 1 |
| Santa Rosa | March 2022 | Replace Rincon bank 1 or 2 with 30 MVA bank |
| Santa Nella | May 2022 | Replace Santa Nella bank 1 and install 12 kV feeder |
| San Jose | May 2022 | Replace Llagas bank 2 w/ 45 MVA or install new 45 MVA at new Spring Sub (Transmission) |
| Madera | June 2023 | Install 1-12 kV feeder - Storey bank 1 |
| Bakersfield | June 2027 | Gosford Substation: construct new substation |
| Paso Robles | June 2027 | Estrella Substation: construct new substation |
| Roseville | June 2027 | Athens Substation: construct new substation |

Source: IDER Incentive Pilots - DPAG Meeting #5 Candidate Project Selection & Prioritization, April 06, 2017

# Three Measure Screen


- PG&E then applied a Certainty/Market screen along with application of “prior-commitment” screen
  - A simple three measure screen resulting in three colors (Red, Yellow and Green) with Overall Green for top priority project

Source: IDER Incentive Pilots - DPAG Meeting #5 Candidate Project Selection & Prioritization, April 06, 2017

# Two Measure Screen

**Certainty**

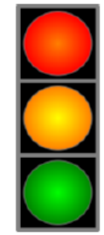
**Metrics:**

- Is load driven by large request from individual customer or by more distributed growth on the circuit/bank? (single customer -- distributed growth)
- What is the size of the projected overload in MW and % of normal operating capacity? (small – large)
- How far in the future is the need? (far – near)

**Market**

**Metrics:**

- Is load driven by large request from individual customer or by more distributed growth on the circuit? (single customer -- distributed growth)
- What is the size of the projected overload in MW relative to the customer population and the total load on the circuit/bank? (large -- small)
- How far in the future is the need? (near – far)



**Overall**

**Metrics:**

- If certainty is red then overall is red.
- If certainty is amber then overall is amber.
- If certainty and market are both green then overall is green.
- All other combinations are amber.

Source: IDER Incentive Pilots - DPAG Meeting #5 Candidate Project Selection & Prioritization, April 06, 2017

# Results

- One 2020 project (Chowchilla) was eliminated
  - Previously designated as DRP Demo C

- Another 2020 project (Single Customer Project X) was eliminated
  - Due to uncertainty of the project, its timing, and
  - Limited opportunity for a DER procurement contemplated in the IDER Pilot

- One 2022 project (San Jose) was eliminated
  - In the process of reviewing bids under a 2016 energy storage RFO

# Results

- Two 2022 projects (Santa Nella) and a 2023 (Madera) were eliminated based upon uncertainty
  - Their projected overloads were relatively small (less than 5%)
  - Per normal planning, PG&E to reassess the need in the next cycle 2017/2018

- The three 2027 projects (all new substations) were eliminated
  - Due to their timing uncertainty
  - Only to provide visibility in PG&E for those responsible for land acquisition

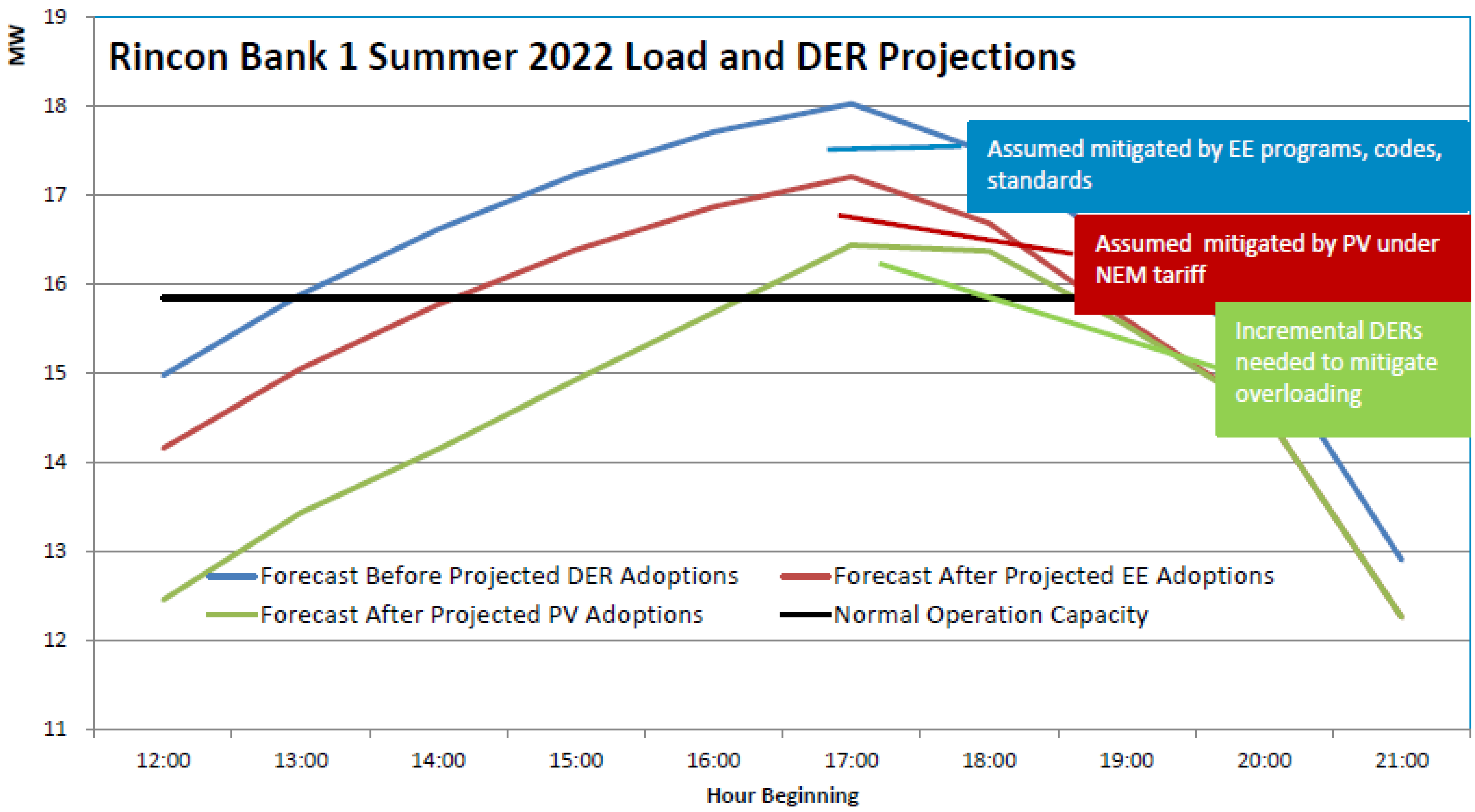
- The 2022 Santa Rosa Project (transformer bank upgrade)
  - Remained as the one “Green Light” candidate project

*- Details in the next slide……*

# Santa Rosa Project

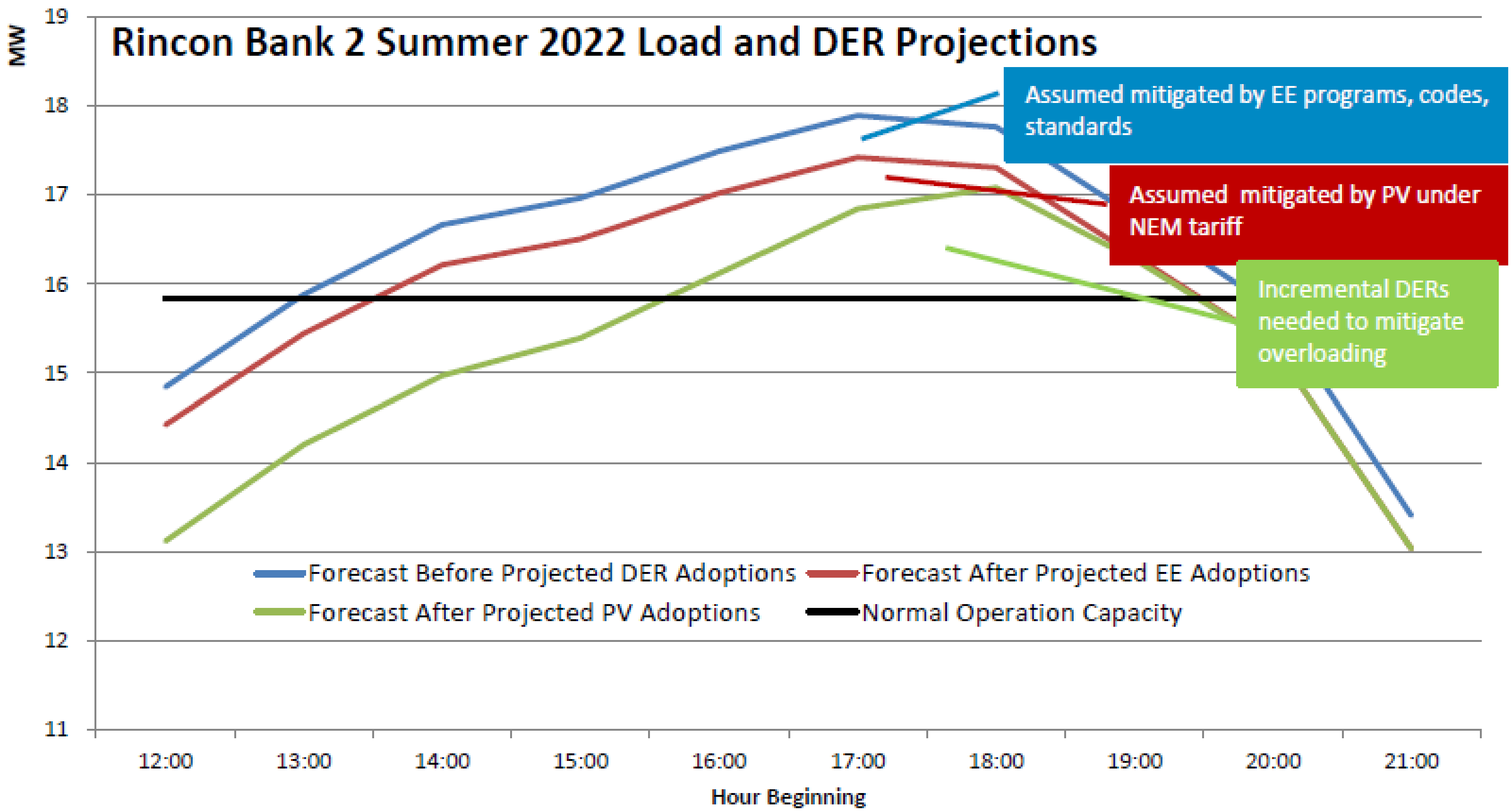
- Relatively certain load and overload; unload two transformer banks
- Mix of customers
  - 13,000 residential, 570 small to medium business
  - 179 large commercial and industrial
- Relatively large deferral
  - 2-3 MW in first year
- Adequate timing for DER development
- Forecasted DER at time of peak need
  - About 2.5 MW from DPAG #5 PPT

# Santa Rosa Project Load & DER Projections Bank 1




Source: IDER Incentive Pilots - DPAG Meeting #5 Candidate Project Selection & Prioritization, April 06, 2017

# Santa Rosa Project Load & DER Projections Bank 2




Source: IDER Incentive Pilots - DPAG Meeting #5 Candidate Project Selection & Prioritization, April 06, 2017

# Discussions/Observations/Recommendations

- Screening used is simple, yet overall covered key parameters for candidate projects
- Project X not a good candidate
- Santa Nella and Madera not pursued under normal planning
- 2027 Substation Projects not good pilot candidates for many reasons
  - Delayed results from the pilot is just one
- Santa Rosa good candidate; may be constraint to rolling load
- 2022 timing is unique among the proposed projects
  - 2022 date for Santa Rosa provides additional opportunity to mitigate contingency risk/cost
  - Potential for delay in availability of some pilot results due to later start

# Nine Candidate Projects

| Location | In-Service Date | Description |
|---|---|---|
| Project X | June 2020 | Install X bank 2 |
| Chowchilla | June 2020 | Replace El Nido bank 1 |
| Santa Rosa | March 2022 | Replace Rincon bank 1 or 2 with 30 MVA bank |
| Santa Nella | May 2022 | Replace Santa Nella bank 1 and install 12 kV feeder |
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| Roseville | June 2027 | Athens Substation: construct new substation |

Source: IDER Incentive Pilots - DPAG Meeting #5 Candidate Project Selection & Prioritization, April 06, 2017

# Discussions – Other Services

- There are some “Voltage Support” projects in < 2020 timeframe
  - Capacitor banks, regulators, circuit reconductorings and load tap changers
  - In first two years of plan
  - Costs are in the range similar to the other utilities
  - Driven by new customers, voltage complaints, other short term reasons
  - Not candidates for IDER Pilot

- Some “Back-tie” projects,
- For completion of main line (via tie)
  - Lower priority and 2017/2018 need

- No utility Micro-grid projects in plan
  - Angel Island proposed as DRP Demo E; CPUC rejected

# Comments/Questions


Q&A

Advice 5096-E

June 16, 2017

**Attachment J1**

PG&E DRAFT RFO Protocol

Pacific Gas and Electric Company

# Integrated Distributed Energy Resources

# Incentive Pilot

# Request for Offers

# DRAFT Solicitation Protocol



## 2017

Integrated Distributed Energy Resources Incentive Pilot
Request for Offers

**DRAFT**

**June 16, 2017**

# Table of Contents

## LIST OF APPENDICES

# I. Introduction and Overview

## I.A. Overview

Pacific Gas and Electric Company ("PG&E") is issuing this 2017 Integrated Distributed Energy Resources (IDER) Incentive Pilot Request For Offers ("RFO" or "Solicitation") to demonstrate the efficacy of distributed energy resouces (DERs) provision of cost-effective electric distribution services , as required by California Public Utilities Commission ("CPUC") Decision ("D.") 16-12-036[1] .

This Solicitation Protocol sets forth the terms and conditions by which PG&E will seek Offers. An entity submitting an Offer in response to this RFO, hereinafter a "Participant," agrees to be bound by all the terms, conditions and other provisions of this RFO as contained in this Solicitation Protocol and any changes or supplements to it that may be issued by PG&E. The obligations of the Participant are further described in Section VII.A, Agreement by Participant.

## I.B. IDER Incentive Pilot RFO Website and Communication

PG&E has established a website at www.pge.com/rfo/IDER, where Participants may access and download all RFO documents, announcements and Q&As that are posted.

To ensure the accuracy and consistency of information provided to all Participants, PG&E prefers that Participants communicate by e-mail to both IDERRFO@pge.com, and to the Independent Evaluator ("IE"), . With respect to a matter of general interest raised by any Participant, PG&E may, without reference to the inquiring Participant, post the question and PG&E's response on PG&E's website. PG&E will attempt to respond to all inquiries, but may decline to respond to any particular inquiry.

All correspondence to and from a Participant will be monitored by the IE, A, who the CPUC selected to oversee this Solicitation. The IE is an independent, third-party evaluator who is required by the CPUC to monitor and evaluate certain competitive solicitations.

## I.C. Schedule Overview

The expected schedule for the RFO is listed in Table I.2 below.

**Table I.1: PG&EIDER Solicitation Schedule**

| | |
|---|---|
| Ongoing: | Participants are invited to register online to receive notices from PG&E regarding the RFO at www.pge.com/rfo |
| tbd | PG&E issues RFO |

[1] Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot D, D.16-12-036.

| | |
|---|---|
| tbd | Participants' Webinar |
| tbd | Deadline for PG&E to receive Offers |
| tbd | Deadline for IE to receive a flash-drive of Offers |
| tbd | PG&E notifies selected Participants that their Offer(s) will be included on a list of Offers for which PG&E may seek to enter into or negotiate an Agreement related to that Offer ("Shortlist") |
| tbd | Participants notify PG&E whether they accept Shortlist status and acknowledge acceptance of the Confidentiality Agreement |
| tbd | PG&E submits Agreements with final Shortlist Participant(s) for CPUC Approval |

The schedule and documents associated with the RFO are subject to change at PG&E's sole discretion at any time and for any reason. PG&E will endeavor to notify Participants of any changes to the RFO, but shall not be liable for any costs or liability incurred by Participants or any other party due to a change or for failing to provide notice or acceptable notice of any change.

PG&E reserves the right to execute agreements resulting from this RFO (each an "Agreement") with any individual Participant at any time after selecting the Shortlist. PG&E's obligations under an Agreement will be conditioned upon PG&E's receipt of CPUC Approval within a stated period of time, as described further in Section XIII, CPUC Approval. PG&E will seek CPUC Approval of all executed Agreements. Participants should factor the CPUC's approval process into their project development timelines and proposals.

### I.D. Events in the RFO Schedule

1) Online Registration: Participants should register at the RFO website http://www.pge.com/rfo to receive timely announcements and updates about this RFO and other RFO-related information via email. Online registration is not required, but is strongly recommended.

2) PG&E issues the Solicitation: All documents associated with the Solicitation, including documents which Participants will need to prepare their Offer, are posted to PG&E's public website under "Integrated Distributed Energy Resources RFO."

3) Participants' Webinar: PG&E will hold a Participants' Webinar on tbd. The Webinar will provide an overview of the RFO and the requirements. Call-in information will be provided on the Solicitation website.

4) Offers Due: Offers must be received by PG&E by 1:00 P.M. Pacific on tbd. Participant Offer package(s) must be submitted through the online platform, Power Advocate. Offer

package(s) must include the documents described in Section V.C, Required Information. PG&E encourages Participants to begin developing their Offer packages early and to send questions regarding the preparation of their Offer(s) to IDERRFO@pge.com. In addition, as described below in Section V.A., Participants must submit their offer materials on a USB flash-drive to the IE for delivery no later than tbd.

PG&E may request a meeting or conference call to discuss a Participant's Offer. The purpose would be to provide PG&E with a full understanding of the details of an Offer for the evaluation process. The IE will be invited to participate in these discussions.

5) PG&E Selects Shortlist: PG&E expects to notify Participants selected for PG&E's Shortlist by tbd. PG&E reserves the right to request additional information and to add additional Participants to the Shortlist following the initial selection.

6) PG&E and Participants Execute Agreements: PG&E expects to negotiate with Participants on the Shortlist and may select any subset of Shortlisted Offers for execution of an Agreement.

7) PG&E Submits Agreements for CPUC Approval: PG&E will seek CPUC Approval of each Agreement, as further described in Section XIII, CPUC Approval.

# II. RFO Goals

## II.A. PG&E Resource Needs

PG&E is seeking to enter into Agreements with DERs ("Projects") that meet the specifications noted in Section IV, Eligibility Requirements.

The proposed location for this pilot demonstration is PG&E's Rincon substation, which is located within PG&E's Santa Rosa distribution planning area and is expected to have overload conditions due to peak demand. Rincon Substation was selected due to its timing certainty and potential for cost-effective DER solutions to address thermal overloadingon peak days.

PG&E is seeking to procure 2-4 MWof DERs to provide load capacity by increasing generation, reducing electrical consumption, or shifting load. The additional distribution capacity needs to be available on or before June 2022 and must be maintained at least throught the end of October 2024.

Dispatchable resources may be called on a day-ahead basis up to 6 times a month for not more than 3 consecutive days and for not more than 12 days total during the summer loading period.

Participants must design, procure, finance, and cause the Project to be constructed, completed, tested and ready for placement into commercial operation in accordance with the following parameters:

Contract term tranches of either:

- June 2020 through October 2024
- June 2021 through October 2024
- June 2022 through October 2024

Delivery Months:

- June through October

Delivery Days:

- Every day of the week

Delivery Hours:

- 3:00 pm to 6:00 pm
- 6:00 pm to 9:00 pm; or
- 3:00 pm to 9:00 pm

Minimum Operation Hours

- 3 consecutive hours per day

Delivery Period:

- Beginning either June 2020, June 2021 or June 2022 andextendign through through October 2024

PG&E does not want the DERs it procures through this RFO to create additional problems on the distribution system. Any DERs procured through this Solicitation must not operate in a manner that negatively impacts the system. Projects may not increase net loading (increase in electrical consumption or decrease in generation) between 3 pm and 9 pm. This restriction applies only on days where the project is dispatched.

## III. PG&E Customer Engagement Support

As part of this Solicitation, PG&E is offering different levels of customer engagement and lead generation support through its Customer Relationship Manager (CRM) team. The intent is to aid Participants in acquiring customers for behind-the-meter Projects by leveraging existing customer relationships, helping target high priority leads, initiating the customer relationship, and ultimately handing off the customer to the Participant. Typical functions of PG&E Customer Relationship Managers include:

- Identify opportunities within targeted territory/customer base

- Cultivate new & existing customer relationships
- Stimulate targeted customer interest, qualifying and generating new leads
- Qualify leads through the understanding of key customer needs

CRM support will be offered on an hourly basis. Participants may select zero, 50 or 200 hours of customer engagement support. Participants selecting 50 or 200 hours of customer engagement support are required to submit an Offer with zero hours.

# IV. Eligibility Requirements

Offers must meet the applicable specifications noted below.

## IV.A. Offer Eligibility

Offers may be for Projects located in-front-of-the-meter or behind-the-meter. Projects must be a DER, which include:

- Demand Response
- Energy Storage
- Energy Efficiency
- Permanent Load Shift
- Renewable Distributed Generation (including curtailment)
- Electric Vehicles

Offers must be for at least 250 kW on a standalone or aggregated basis and may not exceed2 MW.

Offers must be in 250 kW increments.

## IV.B. Resource Double Payment/Double Counting

The goal of this Solicitation is to acquire DERs that are incremental to both existing DERs and DERs that are projected to be adopted during the forecast horizon.

Only DERs that are categorized as wholly incremental or partially incremental will be considered eligible for the purposes of this Solicitation. Participants will have the option of having Offer evaluated for incrementality on a project-specific basis, or having theirOffer evaluated based on a pre-specified overlap factor.

If Participant selects the project specific review, the Offer may be considered between 0% and 100% incremental. If the overlap factor option is selected, the value of the bid will be discounted by 15 % to reflect the overlap between the participants proposal and energy efficiency and distributed generation resources that are projected to be deployed in the local area in the absence of the Offer

For a project-specific review, Appendix B5, Resource Double Payment/Double Counting must be submitted, to show how the proposal is either wholly or partially incremental to ongoing PG&E incentive programs, tariffs, or other solicitations. Offers may be considered either fully incremental or partially incremental. Participants will be required to describe how their proposed Project is incremental to PG&E's programs, tariffs, or other solicitations:

- PG&E's EE program portfolio
- PG&E's DR program portfolio
- PG&E's Self-Generation Incentive Program (SGIP)
- PG&E's Net Energy Metering (NEM) program
- PG&E's energy storage solicitations
- PG&E's renewable generation solicitations

The below table describes what PG&E considers to be wholly, partially, or non-incremental.

| **Category** | **Description** | **Incremental** |
|---|---|---|
| Not already sourced through another program, tariff, solicitation | New technology or service that is not already being sourced or reasonably expected to be sourced through another solicitation, program, or tariff that meets the identified distribution need. | Yes. |
| Partially sourced through another program, tariff, solicitation | Existing technology or service that meets the identified distribution needs but at least some component of that technology or service is already being sourced through another solicitation, program, or tariff. | Yes, but only the portion (if any) that is not currently being sourced or can reasonably be expected to be sourced through another solicitation, program, or tariff with the same locational and temporal granularity and performance guarantees as the bid technology. |
| Wholly sourced through another program, tariff, solicitation | Everything not covered above. | No. The technology is already being sourced or is reasonably expected to be sourced through another solicitation, program, or tariff with the same locational and temporal granularity and performance |

| | | |
|---|---|---|
| | | guarantees as the bid technology. |

### IV.C. Interconnection

Projects must connect or be associated with load facilities that connect to one of the following feeders at the Rincon substation:

- Rincon 1101
- Rincon 1102
- Rincon 1103
- Rincon 1104

There are no minimum interconnection study requirements for an Offer. However, PG&E will assess whether Projects are likely to meet the required online date. Seller should submit any applicable interconnection studies with their Offers.

### IV.D. Measurement and Verification (M&V)

Participants must submit Appendix B7, Measurement and Verification, describing in detail their proposed methodology for measuring distribution services under the Agreement. Preference will be given to proposals that employ existing M&V protocols adopted by the CAISO and CPUC as appropriate to the technology proposed.

## V. Offer Submittal Process

### V.A. Submittal Process Overview

All Offers must be received by tbd at 1:00 P.M. (Pacific), as specified in Table I.2, PG&E IDER Solicitation Schedule.

**Submitting Documents:** All Offers for this RFO ***must*** be submitted electronically through Power Advocate. Prior to submitting an Offer, Participants must register with Power Advocate. PG&E strongly encourages Participants to register with Power Advocate well before Offers are due. PG&E will post detailed instructions on the IDER RFO website for submitting Offer(s) and using the online platform. Power Advocate registrants should be listed under the entity submitting the Offer, the Participant, not its consultants.

Power Advocate Link:

- tbd

Power Advocate functions in most browsers; however it may not work as well in browsers older than Internet Explorer version 8.

Each Offer should be uploaded as a "Commercial" and "Administrative" document type in Power Advocate. If submitting more than one Offer, each Offer should be in separate zip files. Please make sure that file names for your submittals do **not** contain any special characters such as *&#, and please keep file names short, but do include short references to Participant's name (such as an acronym) and the appendix (e.g., App B).

**Electronic Document Formats:** Electronic documents must be submitted as Microsoft Word, Microsoft Excel, or pdf files, as identified in Section V.C, Required Information. However, maps or drawings may be in alternate formats (e.g., jpg, kmz) as appropriate. Each Appendix must be a separate folder or document, not one long document. To the extent possible, pdf files should be provided in a searchable format. The Participant should not provide documents in other electronic formats, unless specifically requested.

## V.B. Number of Offers and Variations Allowed Per Seller

There are no limits to the number of Offers Participants may submit.

## V.C. Required Information

Each Participant's Offer must be complete at the time of submission. Participant's failure to provide all required information may prevent PG&E from being able to evaluate and rank the Offer, which means that the Offer may not be considered for the Shortlist.

Offers must contain all required information and must be organized in accordance with these instructions.

Participants must complete the following documents: (1) the initial Offer package (see Section V.C.1, Offer Package, below); and (2) the post-Shortlist package, if PG&E selects the Participant's Offer for the Shortlist (see Section V.2, Post-Shortlist Documents, below). Participants offer should be consistent with the obligations specified in the term sheet.

Note on Joint Offers: If a Participant is submitting an Offer jointly with another Participant, each Participant will need to be registered as a Participant in Power Advocate separately from any other Participant submitting an Offer and PG&E may require additional documentation or conditions, such as retaining separate legal counsel, restricting the sharing of certain information, or requiring all Participants to the joint Offer to acknowledge acceptance of a modified Confidentiality Agreement and agree to, and execute, modified terms for RFO participation, similar to those set forth in Section VII.A, Agreement by Participant.

## 1. Offer Package

Provide an **Introductory Letter** that describes the Project and all the Offers submitted, including identification of the differences between Offers, such as different Delivery Hours, delivery terms, sized, and technologies. In addition, complete all of the Appendices listed in Table V.1, below.

Price may include a $/kW-month fixed price and may also include a $/kWh variable price to be paid on days when the Project is notified that it is required to provide distribution services.

A separate Offer Form is required for each Offer variation, but an entirely new Offer package is not required; there is no need to submit unchanged, duplicate Appendices if the information is the same; but please provide a short note indicating which sections are duplicative over multiple Offers and which sections are different.

**Table V.1: PG&E IDER RFO Offer Package**

| Appendix | Title | Description | Format |
|---|---|---|---|
| | Introductory Letter | Describe the Project and Offer information. A sample introductory letter outline is provided. | MS Word |
| A | Offer Form | Provide the requested information. | MS Excel |
| B1 | Project Description | Describe the existing or proposed Project, format as single spaced, and include the requested information.<br>Include interconnection study, if applicable | MS Word |
| B2 | Site Control | Provide information relating to the Project's location | MS Word, PDF |
| B3 | Project Milestone Schedule | Provide milestone schedule to support required online date. | MS Word |
| B4 | Experience and Qualifications | Describe the Participant's experience and staff qualifications, including information requested. | MS Word |
| B5 | Resource Double Payment/Double Counting | Describe whether Project or customers are expected to be enrolled in other PG&E programs and how the Project is incremental. | MS Word |
| B6 | Organizational Information | Provide Participant corporate or organizational information, including a certificate of good standing or similar document from Participant's state of formation. The entity name on the certificate must match the name of Participant | MS Word |
| B7 | Measurement & Verification Plan | Describe the Project's methodology for measuring distribution services under the Agreement. | MS Word |

### 2. Post-Shortlist Documents

If the Participant is notified that it is eligible for and accepts PG&E's Shortlist position, then the Participant must complete the Appendices listed in Table VI.2, below. Any delay in providing the Appendices below will impact the Participant's Shortlist position.

**Table V.2: PG&E IDER RFO - Post-Shortlist Appendices**

| Appendix | Title | Description | Format |
|---|---|---|---|
| C | Confidentiality Agreement | Participants must acknowledge acceptance of the Confidentiality Agreement when accepting a position on the Shortlist. | |
| D | Redline of Term Sheet | Provide a redline of the Term Sheet that reflects the Offer(s) Shortlisted | MS Word |
| E | Participant Financial Information | Provide Participant finance information | MS Word |

## VI. Evaluation of Offers

PG&E's evaluation will apply "least-cost, best-fit" principles, using quantitative and qualitative criteria to evaluate the submitted Offers.

PG&E will evaluate Offers using quantitative and qualitative criteria, which may include, but are not limited to:

<u>Quantitative Attributes:</u>
Net Market Value (NMV)

a) Benefits (Distribution Deferral Value)
b) Fixed and Variable Costs

<u>Qualitative Attributes:</u>

a) Project Viability (experience, technology viability, interconnection, site control)
b) Supply Chain Responsibility
c) Technology, Counterparty Concentration
d) Safety

**Quantitative Attributes**

PG&E will perform a quantitative evaluation of each complete Offer conforming to the RFO requirements and rank those Offers based on each Offer's net market value per unit – from highest to lowest. The net market value per unit is calculated using total net market value in dollars for the numerator, and average monthly volume in kilowatts for the denominator. The result of the quantitative analysis is a merit-order ranking of all complete and conforming Offers.

NMV compares an Offer's costs to its market value. NMV is calculated for each Offer as follows:

Net Market Value = D – (F + V)

where

D = Distribution Deferral Value
F = Fixed Cost
V = Variable Cost

1. Distribution Deferral Value ("D")

Distribution deferral value represents the value that an Offer provides by allowing PG&E to defer an otherwise planned investment.

2. Fixed Cost ("F")

The Fixed Cost for an Offer will be calculated as the sum of the projected monthly fixed payments, based on the Capacity Price of $/kw-month specified in the Offer.

Each Offer will also be assigned an annual fixed overhead cost independent of the size of the Project, representing administrative costs.

Each Offer that selects the use of PG&E's Customer Engagement support hours will be assigned a fixed cost based on the number of hours chosen.

3. Variable Cost ("V")

Variable cost will be calculated as the sum of the projected monthly variable payments, based on the number of times PG&E anticipates needing distribution services for a month and the variable O&M price in $/kWh specified in the Offer.

**Qualitative Factors**

**a) Project Viability**

Project viability means the likelihood that the Project under an Offer can be successfully developed and then provide the product for the period stated in the Offer. This assessment is based on a review of the status and plans for key Project activities (e.g., financing, site control, permitting, engineering, procurement, construction, interconnection, start-up and testing, operations, etc.) as well as experience and technology evaluation.

**b) Supply Chain Responsibility**

PG&E may consider Participant's status as a Small Business Administration self-certified small business. PG&E is committed to supply chain responsibility which includes supplier diversity, sustainability and ethical supply chain practices. The Supplier Diversity Program, launched in 1981, aims to provide diverse suppliers with economic opportunities to supply products and services. The Supplier Sustainability Program, launched in 2007, encourages supplier responsibility, excellence and innovation.

Promoting an ethical supply chain means that Health and Safety, Labor Issues and Human Rights, Ethical Business Conduct and Conflicts of Interest are important considerations in supplier selection.

Additional information on PG&E's DBE program can be found at:
www.pge.com/supplychainresponsibility

**c) Counterparty and Technology Concentration**

PG&E may consider the volume of energy or capacity already under contract from a particular counterparty, as well as Offers submitted in this RFO.

**d) Safety**

PG&E may consider Participants' commitment to safety, based on the safety history and practices of the entities that will construct, operate, or maintain the Projects and safety information related to the technology for the Project and Project development.

Any or all qualitative factors may impact a Project's status for Shortlisting or Agreement execution.

## VII. Terms for RFO Participation

### VII.A. Agreement by Participant

Each Participant submitting an Offer shall provide their electronic signature of a duly authorized officer of Participant in the Offer Form. By providing such signature the Participant (a) agrees to be bound by all terms, conditions and other provisions of this RFO and any changes or supplements to it that may be issued by PG&E, and (b) makes the following representations and warranties:

1. Participant has read, understands, and agrees to be bound by all terms, conditions and other provisions of the RFO.

2. Participant has had the opportunity to seek independent legal and financial advice of its own choosing with respect to the RFO and all Appendices to the RFO.

3. Unless otherwise specified in the Offer Form, Participant is not PG&E, an affiliate of PG&E, PG&E Corporation, or any of their affiliates.

4. Participant has obtained all necessary authorizations, approvals and waivers, if any, required of Participant as a condition of: (i) submitting its Offer and, if Participant's Offer is selected; (ii) executing an Agreement with PG&E at the conclusion of negotiations.

5. Participant is submitting its Offer subject to all applicable laws including, but not limited to, D.17 -02-007, the Federal Power Act and all amendments thereto, and Public Utilities Code section 454.5, and all amendments thereto.

6. Participant represents that it has carefully considered the terms and conditions of its Offer and that it is submitting its Offer in good faith, such that PG&E may reasonably expect Participant to enter into a definitive Agreement, and to negotiate, if requested by PG&E, as provided in Section XI, Execution of Agreement, below.

7. Participant has not engaged in and will not engage in communications with any other Participant in the RFO concerning any terms contained in Participant's Offer, unless explicitly authorized by PG&E, and has not engaged in activities in violation of State or Federal antitrust laws or other unlawful or unfair business practices in connection with the RFO (“Prohibited Communication Activities”).

   Notwithstanding the foregoing, Participant may engage in communications with its advisors, counsel, experts or employees who have a need to know the content of the communications and have agreed to keep such information confidential (collectively, “advisors”). In addition, Participant may engage in communications with other Participants submitting an Offer in the RFO and their advisors (“Other Participants”), so long as: (1) such Other Participants are under common ownership and control with Participant; (2) Participant and Other Participants do not engage in Prohibited Communication Activities; and (3) in the event Participant and Other Participant share a common advisor, Participant has, prior to sharing communications with such Other Participant and the common advisor, provided PG&E with (a) notice of such Other Participant and common advisor and (b) an attestation that Participant has not and will not engage in Prohibited Communication Activities with either the Other Participant or the common advisor.

8. If Participant's Offer is selected for the Shortlist and Participant accepts the position on the Shortlist, then Participant agrees to acknowledge acceptance of a Confidentiality Agreement, to negotiate in good faith, and to inform PG&E if the Project that is the subject of the Offer on the Shortlist has been submitted into another solicitation with PG&E or any other entity.

9. If a Participant is submitting an Offer jointly with other entities, and the Offer is selected for the Shortlist, PG&E may require, as part of the shortlisting process, additional representations and warranties, along with additional documentation, from all entities involved in the joint Offer (see Section V.C, Required Information, above).

10. Participant will promptly notify PG&E of any change in circumstances that may affect its ability to fulfill the terms of its Offer, at any time from Offer submission to PG&E's acceptance of the Offer, as evidenced by PG&E's execution of an applicable Agreement, or Participant's withdrawal of the Offer.

A BREACH BY ANY PARTICIPANT OF THE REPRESENTATIONS AND WARRANTIES IN SECTION V.A OF THIS SOLICITATION PROTOCOL, IN ADDITION TO ANY OTHER REMEDIES THAT MAY BE AVAILABLE TO PG&E UNDER APPLICABLE LAW, IS GROUNDS FOR IMMEDIATE DISQUALIFICATION OF SUCH PARTICIPANT FROM PARTICIPATION IN THE RFO AND, DEPENDING ON THE NATURE OR SEVERITY OF THE BREACH, MAY ALSO BE GROUNDS FOR TERMINATING THE RFO IN ITS ENTIRETY.

## VII.B. PG&E's Reservation of Rights

This RFO is an invitation to submit Offers to PG&E; it does not constitute an offer to buy and creates no obligation to execute any Agreement or to enter into a transaction under an Agreement as a consequence of the RFO. PG&E reserves the right to request information from a Participant at any time during the solicitation process. PG&E reserves the right, in its sole discretion, to reject any Offer at any time for any reason, including but not limited to grounds that the Offer does not conform to the terms and conditions of this RFO or contains terms that are not acceptable to PG&E. PG&E also retains the discretion, in its sole judgment, at any time;

(a) to formulate and implement new or additional criteria for the evaluation and selection of Offers; (b) to negotiate with any Participant or withdraw PG&E's Shortlist selection; or (c) to modify this RFO as it deems appropriate to implement the RFO and to comply with applicable law or other direction provided by the CPUC. In addition, PG&E reserves the right to either suspend or terminate this RFO at any time for any reason. PG&E will not be liable in any way, by reason of such withdrawal, rejection, suspension, termination or any other action described in this paragraph to any third party, including any Participant. PG&E will not reimburse the Participant for its expense of participating in this RFO under any circumstances.

### VII.C. Safety

PG&E is committed to providing safe utility (electric and gas) service to its customers. As part of this commitment, PG&E requires that the Participants recognize safety is of paramount importance. In connection with this Solicitation and executed Agreement, Participants will be required to meet certain safety standards, provide safety information related to the technology for the Project, and provide information regarding safety history, including for the entities that will construct, operate, or maintain the Project(s). Per Appendix B8, Participants are required to identify in their Offers known safety-related hazards and risks associated with their Project's technology and Participant's ability to mitigate safety risks and comply with applicable safety-related codes and standards identified by the Participant.

A Participant's obligations with respect to safety may vary based on the particular Agreement and Project and product type, as well as the commercial relationship of the entities involved in the transaction. The Agreement will contain specific requirements intended to ensure that the Participant and the entities that construct, operation, or maintain the Project, as applicable, do so in a safe, reliable and efficient manner that protects the public health and safety of California residents, business, employees, and the community. Participants will be responsible for any fees and costs associated with meeting PG&E's safety requirements in the Solicitation and the Agreement.

## VIII. Confidentiality

Except with PG&E's prior written consent, no Participant shall disclose its participation in this Solicitation (other than by attendance at any meeting held by PG&E with respect to the Solicitation) or collaborate on, or discuss with any other Participant or potential Participant bidding strategies or the substance of any Offer(s), including without limitation the price or any other terms or conditions of any Offer(s).

Except as provided below, all information and documents clearly identified by Participant as "Confidential" on the page(s) on which confidential information appears shall be considered confidential information. PG&E shall not disclose such information and documents to any third parties except for PG&E's or PG&E Corporation's, officers, directors, employees, agents, counsel, accountants, advisors, or contractors who have a need to know such information and have agreed to keep such information confidential and except as provided below. PG&E may use Confidential Information, consolidated with other market information and not specifically attributed to the Provider, to analyze or forecast market conditions or prices, for its own internal use or in the context of regulatory or other proceedings.

It is expressly contemplated that materials submitted by a Participant in connection with this RFO will be provided to the CPUC, its staff, the Independent Evaluator, and PG&E's Procurement Review Group ("PRG"). PG&E will seek confidential treatment pursuant to D.08-04-023, General Order 66-C, and Public Utilities Code section 583, with respect to any Participant-supplied non-public RFO information and documents ("Participant's Confidential Information") that are submitted by PG&E to the CPUC for the purpose of obtaining CPUC Approval. PG&E will also seek confidentiality and/or non-disclosure agreements with the PRG applicable to the Participant's Confidential Information. PG&E cannot, however, ensure that the CPUC will afford confidential treatment to a Participant's Confidential Information, or that those confidentiality agreements or orders will be obtained from and/or honored by the PRG or the CPUC.

With respect to any information or documents provided by the Participant, PG&E shall have the right to disclose to the CPUC, its staff, the Independent Evaluator, the PRG, CAISO, other control area operator or balancing authority and any other entity in order to comply with any applicable law, regulation, or rule or order issued by a court or entity with competent jurisdiction over PG&E, at any time, even in the absence of a protective order, confidentiality agreement or nondisclosure agreement, as the case may be, without notification to the Participant and without liability or any responsibility of PG&E to the Participant.

Once a Participant is selected for the Shortlist, the Participant must acknowledge acceptance of the Confidentiality Agreement in the form attached as Appendix D and within five (5) business days of notification of their selection in order to continue to participate in the RFO. Depending upon Participant's submittal in response to Appendix B6, PG&E may require additional confidentiality obligations with collaborating entities.

## IX. Procurement Review Group Review

Following completion of the evaluation and ranking of Offers, PG&E will submit the results of the evaluation and its recommendations to its PRG. Such information will include at least the all-in cost ranking of Offers, the consideration of non-price evaluation criteria, and PG&E's recommendations based on such information. PG&E has no obligation to obtain the concurrence of the PRG with respect to any Offer.

PG&E assumes no responsibility for the actions of the PRG, including actions that may delay or otherwise affect the schedule for this Solicitation, including the timing of the selection of Offers and the obtaining of CPUC Approval.

## X. Shortlist Notification to Participants

The Solicitation schedule set forth in Section I.C, Schedule Overview, may be modified at PG&E's sole discretion. PG&E expects to be able to provide an e-mail notification to Participants whose Offers have been selected for the Shortlist, and invite each Participant on the Shortlist to conduct discussions and negotiations with PG&E regarding the Offer selected for the Shortlist. PG&E anticipates notifying those Participants whose Offers were not Shortlisted shortly thereafter.

## XI. Execution of Agreement

By submitting an Offer, Participant agrees, if its Offer is selected for PG&E's Shortlist, that it is prepared to (1) enter into a definitive Agreement consistent with the term sheet, and (2) negotiate and execute a definitive Agreement consistent with the Participant's Offer and containing such other terms and conditions as may be mutually acceptable to PG&E and the Participant. PG&E's evaluation of a Participant's Offer and PG&E's Shortlisting of a Participant does not constitute an agreement by PG&E.

## XII. Credit

Upon CPUC Approval of an Agreement with PG&E, the Participant must post collateral to PG&E to mitigate PG&E's risk in the event that the Project is not constructed or placed into commercial operation, or the Participant is otherwise unable to meet the conditions of the Agreement. Participant is required to post collateral in the form of cash or letter of credit from a reputable U.S. bank in the following amounts and by the time discussed below:

Project Development Security: $60/kW for new resources, or $25/kW for existing resources, due within five (5) Business Days following CPUC approval of the Agreement.

Delivery Term Security: The higher of $125/kW or 10% of 3-year capacity payments due by the Online Date.

## XIII. CPUC Approval

Whether an Agreement becomes effective and binding on the parties is expressly conditioned on PG&E's receipt of CPUC Approval, which will be more specifically defined in the Agreement and term sheet. At a minimum PG&E will require a finding from the CPUC that PG&E's entry into the Agreement satisfies PG&E's IDER demonstration compliance requirement, that the terms are reasonable, and that PG&E will recover the costs incurred under the Agreement in its rates. Additionally, the Agreement will be subject to a no-fault termination if CPUC Approval does not occur within a specified period. CPUC Approval typically requires the approval of the Agreement by the CPUC to be final and non-appealable without any modifications that are unacceptable to either of the parties.

## XIV. Waiver of Claims and Limitations of Remedies

Except as expressly set forth in this Protocol, by submitting an Offer, Participant knowingly and voluntarily waives all remedies or damages at law or equity concerning or related in any way to the Solicitation, the Solicitation Protocol and/or any attachments to the Solicitation Protocol ("Waived Claims"). The assertion of any Waived Claims by Participant may, to the extent that Participant's Offer has not already been disqualified, automatically disqualify such Offer from further consideration in the Solicitation or otherwise.

By submitting an Offer, Participant agrees that the only forums in which Participant may assert any challenge with respect to the conduct or results of the Solicitation is through the Alternative Dispute Resolution ("ADR") services provided by the CPUC pursuant to Resolution ALJ 185, August 25, 2005. The ADR process is voluntary in nature, and does not include processes, such as binding arbitration, that impose a solution on the disputing parties. However, PG&E will consider the use of ADR under the appropriate circumstances. Additional information about this program is available on the CPUC's website at the following link:

http://docs.cpuc.ca.gov/published//Agenda_resolution/47777.htm

Participant further agrees that other than through the ADR process, the only means of challenging the conduct or results of the Solicitation is a protest to PG&E's filing seeking CPUC Approval of one or more Agreements entered into as a result of the Solicitation, that the sole basis for any such protest shall be that PG&E allegedly failed in a material respect to conduct the Solicitation in accordance with this Protocol, and the exclusive remedy available to Participant in the case of such a protest shall be an order of the CPUC that PG&E again conduct any portion of the Solicitation that the CPUC determines was not previously conducted in accordance with the Solicitation Protocol. Participant expressly waives any and all other remedies, including, without limitation, compensatory and/or exemplary damages, restitution, injunctive relief, interest, costs, and/or attorney's fees. Unless PG&E elects to do otherwise in its sole discretion during the pendency of such a protest or ADR process, the Solicitation and any related regulatory proceedings related to the Solicitation, will continue as if the protest had not been filed, unless the CPUC has issued an order suspending the Solicitation or PG&E has elected to terminate the Solicitation.

Participant agrees to indemnify and hold PG&E harmless from any and all claims by any other Participant asserted in response to the assertion of a Waived Claim by Participant or as a result of a Participant's protest to an advice letter filing with the CPUC resulting from the Solicitation.

Except as expressly provided in this Protocol, nothing herein including Participant's waiver of the Waived Claims as set forth above, shall in any way limit or otherwise affect the rights and remedies of PG&E.

## XV. Termination of the RFO-Related Matters

PG&E reserves the right at any time, in its sole discretion, to terminate the RFO for any reason whatsoever without prior notification to Participants and without liability of any kind to, or responsibility of, PG&E or anyone acting on PG&E's behalf. Without limitation, grounds for termination of the RFO may include the assertion of any Waived Claims by a Participant or a determination by PG&E that, following evaluation of the Offers, there are no Offers that provide adequate ratepayer benefit.

PG&E reserves the right to change the Offer evaluation criteria for any reason, to terminate further participation in this process by any Participant, to accept any Offer or to enter into any definitive Agreement, to evaluate the qualifications of any Participant, and to reject any or all Offers, all without notice and without assigning any reasons and without liability to PG&E or anyone acting on PG&E's behalf. PG&E shall have no obligation to consider any Offer.

In the event of termination of the RFO for any reason, PG&E will not reimburse the Participant for any expenses incurred in connection with the RFO regardless of whether such Participant's Offer is selected, not selected, rejected or disqualified.

Advice 5096-E

June 16, 2017

# Attachment J2

Appendix B1-B8 - Integrated Distributed Energy Resources Incentive Pilot RFO

Supplemental RFO Documents Required for Participation

Pacific Gas and Electric Company®

# Integrated Distributed Energy Resources Incentive Pilot RFO

# Supplemental RFO Documents Required for Participation

# Contents

# Appendix B1: Project Description

**Participant Name:**

PG&E reserves the right to request additional documentation listed but not already provided in the Offer package.

Please provide the following Project information in the order requested. Indicate if a question is not applicable and do not leave responses blank.

**1. SYSTEM DESCRIPTION**

A general description of the distributed energy resource system, including any control and communications system.

For Projects that are modifying load, please describe how the system will provide distribution services, including any modifications to customer behavior and asset relocations.

**2. TECHNICAL/EQUIPMENT DESCRIPTION**

A summary of the technical characteristics of the Project, including:

(i) a listing of the major components (equipment) to be used;

(ii) information relating to the availability of and Participant's access to the equipment and components utilized / proposed for construction and operation of the Project;

(iii) equipment source (e.g. existing owned inventory, new manufacturer order, resale market purchase, etc.);

(iv) terms and expiration of warranties/guarantees;

(v) a non-confidential description of any new or proprietary processes in manufacturing, deployment, operation, etc.; and

(vi) any other relevant technical information about the Project and supply chain considerations.

(vii) Has the equipment/application proposed been applied in commercial operations? If so, provide examples. If the technology/equipment has not been used commercially, please describe the status of the application.

(viii) Please indicate if you have patent or license rights to new or proprietary processes, equipment, hardware/firmware/software, or systems necessary for the successful operation of the Project.

## 3. OPERATING PARAMETERS

To give PG&E an understanding and confidence that the proposed operation of the Project is achievable, provide the following information:

(i) Describe specific design considerations and provide, where appropriate, significant design detail to confirm that the Project has been designed to accommodate planned operations. Components that should be specifically addressed are specific to your technology, such as PV panels, battery cells, inverters, auxiliary equipment, etc.

(ii) List known or expected operating characteristics of the Project. Provide any manufacturer-provided operating specifications.

## 4. CUSTOMER ACQUISITION

For behind-the-meter projects, please describe the plan for acquiring customers.

## 5. PERMITTING

Please complete the following table of permits and discretionary approvals required from local, state, federal, and/or tribal authorities for both the Project and any interconnection related upgrades under consideration. Include those permits that are required but not currently held, the status of permits in the application phase, and the expiration date of all discretionary permits already obtained and the agency process for granting a permit extension. Provide links to agency or applicant web sites where permit information is available.

| Table of Discretionary Land Use Permits and Approvals Required from Local, State, Federal, and/or Tribal Authorities for the Project and any Interconnection Upgrades |
|---|

| **Permit Type or Approval** | **Issuing Agency/Entity** | **Date Issued *Or* Date application submitted and Date anticipated** | **Permit Expiration Date*** |
|---|---|---|---|
| *EXAMPLE: Conditional Use Permit* | *Alameda County, CA* | *Issued 1/1/2015* | *Expires 1/1/2018* |
| [List additional permits, as necessary.] | | | |
| * Describe the agency process for granting a permit extension and the length of the extension. | | | |

## 6. ENVIRONMENTAL RESOURCE REVIEWS AND APPROVALS

Please provide the following information, identifying all required environmental resource reviews, permits or approvals obtained, in progress, or anticipated for the Project, including but not limited, to those listed below. Indicate permit/approval status and anticipated issuance or approval date. Provide links to agency or applicant web sites where agency environmental review and determination documents (i.e., EIR, EIS) and Project environmental study documents are available. If applicable, indicate if environmental reviews are not required by the permitting agency for the Project, and why.

**(i) CEQA/NEPA Review**

- NEPA Lead Agency (if required)
  - Type of Document - EA/FONSI or EIS
  - Date Final Document Approved, or estimated approval date
- CEQA Lead Agency (if required)
  - Type of Document - NegDec, Mitigated NegDec or EIR
  - Date final document approved, or estimated approval date
  - State Clearinghouse Number

**(ii) Endangered Species**

- USFWS Section 7 Consultation (if required)
  - Federal agency initiating consultation
  - Type of Consultation – Informal, Formal
  - Type of USFWS Response – Concurrence or Biological Opinion & Incidental Take Permit
  - Date Consultation Completed or estimated completion date

- California DFW Consultation (if required)
- Incidental Take Permit (if required)
- Date Incidental Take Permit received or estimated receipt date

**(iii) Cultural Resources**

- If required, provide Native American stakeholders to be consulted. If they have been consulted, then please provide contact dates.
- Status of Section 106 review, if required
- Describe any cultural resources on the Project Site eligible for or listed on national or state registers

**(iv) Water Resources**

- Describe any "will serve" commitments from the local water provider for the Project, and provide the name of the local provider
- Date commitment received or estimated receipt date

As applicable, please provide any additional permitting and environmental information for the items below, as this could support the Project Viability assessment. Provide impact information and mitigation plans when relevant. If information is not available, please indicate as such.

(i) Hazardous Materials/Waste (i.e., type and volumes)

(ii) Water Quality and Supply (i.e, source, amounts, on-site usage and discharge)

(iii) Air Quality

(iv) Stakeholder Engagement (i.e., anticipating and addressing public concerns about the Project)

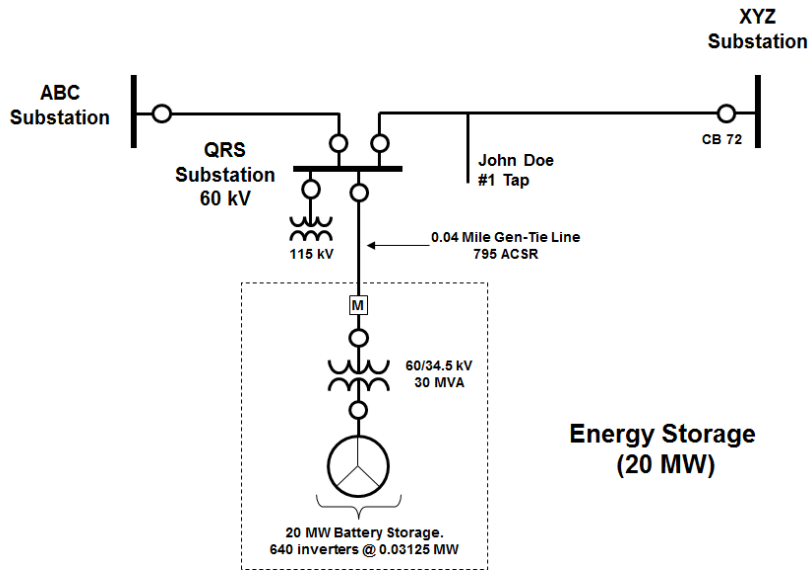
**7. PRELIMINARY DESIGN**

Provide the following preliminary design information used as the basis for the facility design and associated performance guarantees. Depending on the technology of the project offered, some sections will not apply.

(i) General Arrangement Drawings

(ii) Plot Plan

(iii) Single-Line Diagrams with metering and Point of Interconnection clearly shown




**EXAMPLE SINGLE-LINE DIAGRAM**

(iv) Heat Balance Diagram
For those resources that burn fuel, then provide a heat balance diagram for each fuel type used. Heat balances for each fuel to be permitted shall include the mass flow rate (lb/hr), temperature (°F), pressure (psia), and enthalpy (BTU/lb) for all energy, water, steam, combustion air, and fuel streams entering and exiting the boundaries of the generating unit and of each major equipment component. The heat balances shall be provided for each fuel that will be permitted for use at the facility. The fuel constituents and heating value shall be provided for each of the fuels.

(v) Piping & Instrument Diagrams (P&ID)
The Piping and Instrument Diagrams ("P&IDs") should include line sizes, instrumentation, and valves for all major systems that will be provided by Participant. The Participant shall also provide a list of all system P&IDs that will be prepared during the design phase of the Project.

## 8. INTERCONNECTION

Provide the following information regarding interconnection:

(i) Provide a written description of your interconnection plans and any known network requirements that may be needed.

(ii) List the current or proposed point of interconnection to the distribution system, and the distance from the Project to the electric interconnection point.

(iv) Status of Project's studies associated with the interconnection process, along with any application fees paid. Expected dates for: (i) the completion of the various studies associated with the interconnection process; (ii) the completion of any upgrades required for interconnection; and (iii) the ultimate availability of the interconnection.

(v) Completed interconnection study or interconnection agreement, if applicable.

## 9. GAS INTERCONNECTION

If applicable, provide a description of the existing/proposed gas interconnection including but not limited to a description of the interconnecting utility, gas application status, gas agreement dates, etc.

## Appendix B2: Site Control (applicable to Front of the Meter projects only)

**Participant Name: ___________________**

PG&E reserves the right to request additional documentation regarding items listed but not already provided in the Offer package.

Please provide the following project information in the order requested. Indicate if a question is not applicable and do not leave responses blank.

1. Geographic Coordinates of the Project
   Provide Township/range/section numbers and latitude/longitude of the land on which any portion of the Project is proposed.

2. APN Number and Site Address
   Please provide the County Assessor's parcel number (APN) and site address.

3. Street map, Aerial, or USGS map
   Provide a map that shows the assessor parcel boundary(ies), the Project boundary, and location of the Project's key facilities such as transformer or substation and distribution line interconnection.

4. A Digital Map
   Please provide the map of the Project boundary, access roadways, and the rights-of-way for all interconnecting utilities in either one of the following formats:

   i. Google kml/kmz, ESRI shapefile or other GIS data file with specific projection information for GIS files. Instructions for generating a GIS file using Google Earth can be found on the RFO website on www.pge.com/rfo.

   ii. A digital map (.pdf, .jpg, tiff, etc.) of the aerial street or USGS topo background.

5. Elements of Site Control
   Please specify the legal and property interests through which the Participant or Project will exercise control over the land on which the Project and other appurtenances required for the operation and maintenance of the Project are situated for the entire term of the

proposed Agreement.

For example, interests may include fee ownership, lease, easement. Interests may be existing or exercisable options. If interests are contingent, please specify the nature and timing of the contingencies.

Please identify any interests in land that Participant does not have, but would be required for the operation and maintenance of the Project or appurtenances.

# Appendix B3: Project Milestone Schedule

**Participant Name:**

PG&E reserves the right to request additional documentation to support information listed but not already provided in the Offer package.

Please provide a Project milestone schedule describing financing, permitting, engineering, procurement, construction, interconnection, and startup activities, timelines and status. The schedule should include major activities and milestones for all aspects of the Project (including financing, interconnection, permitting, equipment procurement, construction, synchronization, and commercial operations) since project inception through the first year of commercial operation along with a supporting narrative.

[*Sample milestones for illustration only. Participant to insert project-specific list.]*

| *No.* | *Date* | *Milestones* |
|---|---|---|
| 1 | | Demonstrates site control / customer acquisitions. |
| 2 | | Submits interconnection application. |
| 3 | | Files any discretionary agency permit applications (i.e. environmental, land use). |
| 4 | | Files ministerial/construction permit application(s). |
| 5 | | Receives a completed System Impact Study or Phase I Interconnection Study. |
| 6 | | Obtains control of all lands and rights-of-way comprising the Site. |
| 7 | | Receives a completed interconnection Facility Study or Phase II Interconnection Study. |
| 8 | | Executes an interconnection agreement and transmission/distribution service agreement, as applicable. |
| 9 | | Receives FERC acceptance of interconnection agreement and transmission agreement. |
| 10 | | Receives discretionary agency permit (i.e. environmental, land-use). |
| 11 | | Receives ministerial/construction permits. |

| | | |
|---|---|---|
| 12 | | Executes contract |
| 13 | | Procures the ________________________________________*[insert applicable distributed energy resource equipment]* for the Project. |
| 14 | | Completes financing, including construction financing. |
| 15 | | Begins construction of the Facility. |
| 16 | | Begins startup activities. |
| 17 | | Initial Performance Test. |
| 18 | | Commercial Operation Date. |

# Appendix B4: Experience and Qualifications

**Participant Name:**

PG&E reserves the right to request additional information to support documentation listed but not already provided in the Offer package.

Provide information in the order requested. Indicate if a question is not applicable and do not leave responses blank.

Please describe the Participant's experience and staff qualifications, including but not limited to:

1. Organizational chart for the Project that lists the Project participants and identifies the management structure and responsibilities.

2. The staff make-up and size and the identification and brief description of Participant's key personnel and management.

3. Experience and qualifications in developing, designing and constructing, and operating and maintaining distributed energy resource facilities, as well as contracting to sell and deliver long-term power supplies. Participant should highlight their experience in these areas as it relates to:

   - projects utilizing the same technology as the proposed Project;
   - projects of similar capacity and configuration as the proposed Project;
   - specific engineering, procurement and construction (EPC) contractors being considered for this Project; and
   - projects supplying distributed energy resources and/or energy to California.

4. Participant experience and history in financing distributed energy resource facilities, along with the financing plan and expected financing sources for the proposed Project. Identify any government assistance / program to be requested, expected, or received that would affect financing of this project.

# Appendix B5: Resource Double Payment/Double Counting

**Participant Name:**

1. For wholly incremental consideration, please provide a qualitative description of how the Project is, and will continue to be throughout the delivery term, new and wholly incremental to PG&E's programs, tariffs, or solicitations.

2. For wholly incremental consideration, please provide a quantitative estimate (in kw and kwh) establishing how the Project will provide, and continue to provide Distribution Services throughout the delivery term, distribution services that are new and wholly incremental to PG&E's programs, tariffs, or solicitations.

2. For partial incremental consideration, please provide a qualitative description of how the Project is, and will continue to be throughout the delivery term, a modification or enhancement to PG&E's programs, tariffs, or solicitations.

3. For partial incremental consideration, please provide a quantitative estimate (in kw and kwh) establishing how the Project will provide, and continue to provide Distribution Services throughout the delivery term, distribution service that are incremental to the distribution service provided by PG&E's programs, tariffs, or solicitations.

Examples

| Category | Example | Incremental |
|---|---|---|
| Not already sourced through another program, tariff, solicitation | An "add-on" program to any already deployed DER that would allow that already deployed DER to provide the distribution services solicited (for example, a demand response program that utilizes existing thermostats, DG, energy storage, or electric vehicles).<br><br>A new load modifying demand | Yes, if the existing resources without the "add on" were not capable of providing the distribution service. |

| Category | Example | Incremental |
|---|---|---|
| | response program that provides the local distribution services solicited (for example, an appliance DLC program).<br><br>An energy efficiency technology or program that is not already included in PG&E's energy efficiency program portfolio. | |
| Partially sourced through another program, tariff, solicitation | Offering an enhanced incentive to increase uptake of a DER in an area over what would be expected under the base program, tariff, solicitation (for example, converting an existing energy efficiency co-pay program to a direct install program or offering enhanced incentives to increase uptake of DG or ES in a local area). | Yes, but only the portion (if any) that is not currently being compensated for by the existing base program, tariff, solicitation.<br><br>There would be a high bar in this case for the vendor to show that the enhanced incentive will increase uptake. |
| Wholly sourced through another program, tariff, solicitation | Bidder submits bid for rooftop PV that is already compensated under NEM tariff without material enhancement.<br><br>Bidder submits bid for DG or ES that is already compensated for under SGIP without material enhancement.<br><br>Bidder submits bid for EE or DR program that is already in PG&E's EE or DR portfolio without material enhancement. | No, distribution services have already been compensated for under existing programs or tariffs. |

# Appendix B6: Organizational Information

**Participant Name:**

**A. Participant Organizational Information:**

1. Indicate the full, complete and correct Legal Name of Participant and provide copy of a certificate of good standing or similar document from Participant's state of formation. The entity name on the certificate must match the name of Participant:

2. Describe in detail Participant's organizational structure. A written description and a box diagram showing links are both helpful. If applicable, list the legal names of the participants of a joint Offer Participants, owners of the Project (if different than the Participant) and the relative percentage ownership of Participant of the Project, and in addition address all of the following if applicable:

   - Participant is a direct or indirect subsidiary or affiliate of any other entity or corporation provide detail as to the relationships and identify the ultimate parent;
   - Participant is part of a partnership, provide the names of all partners and indicate the general partner(s);
   - Participant is a joint venture, identify the members of the joint venture and indicate if any is the controlling entity;
   - Participant a limited liability company, identify the members;
   - Participant is acting as a member of a consortium or other organization, association or group of persons acting in concert for purposes of submitting a joint Offer, provide the names of all the members and indicate the controlling member of the consortium, organization, association or group.

3. Provide the name of the principal state where the entities named in item A.2 above are registered or incorporated with an "active" status. If Participant is incorporated outside of California but is also registered in California, but under a different name, please provide that name.

4. Please identify the parties (including Participant's entity) you believe will need to know "Confidential Information" (as that term is defined in the Confidentiality Agreement, Appendix D) during any upcoming negotiations of your Offer with PG&E. If you are the only party with a need to know, just indicate that.

5. List and describe any pending legal disputes that may affect the Participant's ability to enter into or fulfill its ability to perform under the proposed Offer.

6. Provide the name and contact information of your legal counsel representing you in this Offer, if PG&E requests further information or clarification or needs to address conflicts of interest.

# Appendix B7: Measurement and Verification (M&V)

**Participant Name:**

1. Please describe in detail the methodology for determining distribution services provided under the Agreement. How will project performance be verified throughout the delivery term? Please indicate the use of existing M&V protocols adopted by the CAISO or CPUC as appropriate to the technology proposed, such as revenue-quality interval meters, accepted baseline methodologies, and IPMVP. Please describe any metering systems and configurations.

2. Please describe any modeling tools or software that will be used for measurement and verification. Are any of the proposed modeling tools or software that will be used proprietary or requiring special licensing? If yes please provide a brief description.

For Projects utilizing a baseline methodology:

3. Please describe baseline conditions used to quantify the amount of distribution services provided by the Project. Please identify what minimum code/and or industry standard practice will be used to establish the baseline, as well as the pre-installation baseline time period proposed.

4. Please describe any post-installation components that will be used to revise or reconcile pre-installation baseline conditions.

5. Please describe which independent variables will be used to quantify baseline conditions (e.g., temperature, production rates, etc.).

# Appendix B8: Safety

**Participant Name:**

1. Describe all known safety hazards associated with the distributed energy resource and configuration planned for the Project. Provide descriptions of the systems or processes typically used to manage or mitigate any risks associated with the known safety hazards.

2. Identify the relevant industry safety-related codes or standards and government regulations that apply to the design and operation of the distributed energy resource using the proposed technology and configuration (e.g. NEC Article 480 for stationary energy storage, etc.).

3. Provide a description of any ongoing processes used by the distributed energy resource original equipment manufacturer (OEM) and its customers to communicate lessons learned about its installed projects to identify, resolve, and prevent potential safety-related issues.

4. Provide the safety record of the Participant and identified contractors associated with the Project, and identify subsequent actions taken to manage or mitigate any safety incidents. Provide documentation for the previous three years (2014-2016) to demonstrate Participant's (if applicable) and/or associated contractors' Occupational Safety and Health Administration (OSHA) Recordable Incident Rates and Experience Modification Rates.

Advice 5096-E

June 16, 2017

# Attachment J3

Appendix C - CONFIDENTIALITY AGREEMENT DRAFT

## CONFIDENTIALITY AGREEMENT

This confidentiality agreement ("Confidentiality Agreement") is entered into by and between Pacific Gas and Electric Company, a California corporation, ("PG&E") and Participant as indicated on its Shortlisted Offer, each of which may be referred to herein separately as a "Party" or together as the "Parties" and is entered into and dated as of the date of PG&E's Shortlist notification to Participant ("Execution Date").

Whereas, each Party ("Provider") may have furnished and is furnishing to the other Party ("Recipient") certain Confidential Information, as defined below, in order to assess Participant's offer to sell certain products and services as submitted into PG&E's Integrated Distributed Energy Resources ("IDER") Solicitation ("Solicitation") pursuant to California Public Utilities Commission Decision (D).16-12-036 and the negotiation of an agreement ("Agreement") in connection with the Solicitation, if applicable;

Whereas, it is to the mutual benefit of each Party hereto to enter into this Confidentiality Agreement and provide for the procedure to exchange and protect Confidential Information, as defined below, pursuant to this Confidentiality Agreement;

NOW, THEREFORE, in consideration of Provider's disclosure to Recipient of Confidential Information and other valuable consideration, the Parties agree as follows:

### 1. Definition of Confidential Information

The term "Confidential Information" shall mean all information that either Party has furnished or is furnishing to the other Party, which with respect to Participant as Provider must in addition be clearly marked "Confidential" (or promptly identified in writing as such when furnished to PG&E in intangible form), in connection with or pertaining to the Solicitation or any Agreement , whether furnished before or after the Execution Date of this Confidentiality Agreement, whether intangible or tangible, and in whatever form or medium provided, and regardless of whether owned by Provider, as well as all information generated by Recipient or its Representatives, as defined below, that contains, reflects, or is derived from such furnished information. "Confidential Information" shall also include information regarding the Parties' bidding and negotiation process, including the status of such process, and potential commercial relationship concerning the Solicitation or any Agreement. Capitalized terms not otherwise defined herein shall have the respective meaning given in the Solicitation.

### 2. Disclosure to Representatives

Recipient agrees that it shall maintain the Confidential Information in strict confidence and that the Confidential Information shall not, without Provider's prior written consent, be disclosed by Recipient or by its affiliates, or their respective officers, directors, partners, employees, agents, or representatives (collectively, "Representatives") in any manner whatsoever, in whole or in part, and shall not be used by Recipient or by its Representatives other than in connection with the Solicitation and the evaluation or negotiation of the Agreement; provided that, PG&E may use Confidential Information, consolidated with other market information and not specifically attributed to the Provider, to analyze or forecast market conditions or prices, for its own internal use or in the context of regulatory or other proceedings. Moreover, Recipient agrees to transmit the Confidential Information only to such of its Representatives who need to know the Confidential Information for the sole purpose of assisting Recipient with such permitted uses, as applicable; provided that, Recipient shall inform its Representatives of this

Confidentiality Agreement and secure their agreement to abide in all material respects by its terms. In any event, Recipient shall be fully liable for any breach of this Confidentiality Agreement by its Representatives as though committed by Recipient itself.

3. **Nondisclosure**

Recipient further agrees that it:

(a) shall not disclose any Confidential Information provided to it by Provider to any third party for any purpose, except as provided in Section 5 below (or Section 2 above if a Representative is a third party);

(b) shall not distribute all or any portion of Confidential Information to any Representative for any purpose other than as permitted by Section 2 above; and

(c) shall destroy or return all such Confidential Information upon Provider's request; provided that, each Party shall have the right to retain one copy of Confidential Information for regulatory compliance or legal purposes, and neither Party shall be obligated to purge extra copies of Confidential Information from electronic media used solely for disaster recovery backup purposes.

**4. Exclusions to Confidential Information**

For purposes of this Confidentiality Agreement, Confidential Information does not include information that:

(a) is in the public domain at the time of the disclosure by Provider or is subsequently made available to the general public through no violation of this Confidentiality Agreement by Recipient;

(b) Recipient can demonstrate was at the time of disclosure by Provider already in Recipient's possession and was not acquired, directly or indirectly, from Provider on a confidential basis;

(c) is independently developed by Recipient without use of or reference to the Confidential Information; or

(d) is disclosed with the prior written consent of Provider.

**5. Required and Permitted Disclosure**

Recipient agrees not to introduce (in whole or in part) into evidence or otherwise voluntarily disclose in any administrative or judicial proceeding, any Confidential Information**,** except as required by law or as Recipient may be required to disclose to duly authorized governmental or regulatory agencies ("Required Disclosure"). In the event that Recipient or any of its Representatives becomes subject to a Required Disclosure, Recipient agrees:

(a) to the extent practicable, to use reasonable efforts to notify Provider prior to disclosure and to prevent or limit such disclosure; and

(b) if disclosure of such Confidential Information is required to prevent Recipient from being held in contempt or subject to other legal detriment, to furnish only such portion of the Confidential Information as it is legally compelled to disclose and to exercise its reasonable efforts to obtain an order or other reliable assurance that confidential treatment will be accorded to the disclosed Confidential Information.

After using such reasonable efforts, Recipient shall not be prohibited from complying with the Required Disclosure and shall not be liable to the other Party for monetary or other damages incurred in connection with the Required Disclosure.

In addition to the Required Disclosure, PG&E shall be permitted to disclose Confidential Information as follows: (i) to PG&E's Procurement Review Group ("PRG"), as defined in California Public Utilities Commission ("CPUC") Decision (D) 02-08-071 and subject to confidential treatment by PRG members; (ii) to the CPUC (including CPUC staff) under seal for purposes of review (if such seal is applicable to the nature of the Confidential Information), and (iii) to the Independent Evaluator, as defined and specified in the PG&E Integrated Distributed Energy Resources ("IDER") Solicitation Protocol ("Protocol"). PG&E shall also be permitted to disclose Participant's Confidential Information in order to comply with (A) any applicable law, regulation, or any exchange or control area rule, or (B) any applicable regulation, rule, or order of the CPUC, California Energy Commission, the California Air Resources Board, or the Federal Energy Regulatory Commission, including any mandatory discovery or data request issued by any of the foregoing entities.

## 6. No License Rights

This Confidentiality Agreement and any Confidential Information used or disclosed hereunder shall not be construed as granting, expressly or by implication, Recipient any rights by license or otherwise to such Confidential Information or to any invention, patent or patent application, or other intellectual property right, now or hereafter owned or controlled by Provider.

## 7. Publicity

Subject to Sections 4 and 5, neither Party will disclose any information or make any news release, advertisement, public communication, response to media inquiry or other public statement regarding this Confidentiality Agreement and the Confidential Information disclosed hereunder (including without limitation the potential commercial relationship between the Parties, the inclusion of an offer on PG&E's shortlist of offers, or the status of negotiations) or the performance hereunder or with respect to an offer, without the prior written consent of the other Party.

## 8. No Future Contracts

Entry into this Confidentiality Agreement and the disclosure of Confidential Information hereunder shall not constitute an offer or acceptance or promise of any future contract or amendment of any existing contract. Each Party shall retain such rights with respect to its own Confidential Information as it had prior to entering into this Confidentiality Agreement. Neither Party shall have any legal obligation with respect to any contemplated transaction because of this Confidentiality Agreement nor any other written or oral expression with respect to any transaction except, in the case of this Confidentiality Agreement, for the matters specifically agreed to herein.

### 9. No Representation or Warranties

Any Confidential Information exchanged under this Confidentiality Agreement shall carry no warranties or representations of any kind, either expressed or implied, unless specifically expressed per the terms of the Protocol. Recipient shall not rely on the Confidential Information for any purpose other than to make its own evaluation thereof or as provided in the Protocol.

### 10. Injunctive Relief

Recipient acknowledges and agrees that, in the event of any breach of this Confidentiality Agreement, Provider may be irreparably and immediately harmed and monetary damages may not be adequate to make Provider whole. Accordingly, it is agreed that, in addition to any other remedy to which it may be entitled in law or equity and, with respect to PG&E as Provider any remedy under the Protocol, Provider shall be entitled to an injunction or injunctions (without the posting of any bond and without proof of actual damages) to cease breaches or prevent threatened breaches of this Confidentiality Agreement and/or to compel specific performance of this Confidentiality Agreement, and that neither Recipient nor its Representatives will oppose the granting of such equitable relief if a court finds a breach or threatened breach. Each Party expressly agrees that it shall bear all costs and expenses, including attorneys' fees and costs that it may incur as Provider in enforcing the provisions of this Confidentiality Agreement.

### 11. Term and Provisions Surviving Termination

This term of this Confidentiality Agreement shall be two (2) years from the Execution Date; provided however, that either Party may earlier terminate this Confidentiality Agreement by giving the other Party thirty (30) days prior written notice of its intention to terminate this Confidentiality Agreement. Any such expiration or termination shall not abrogate either Party's obligations hereunder with respect to Confidential Information received prior to such expiration or termination nor those terms herein relating to the interpretation or enforcement of this Confidentiality Agreement relating to said obligations. Such obligations and terms shall survive for a period of three (3) years from said expiration or termination.

### 12. No Waiver

Any waiver of any provision of this Confidentiality Agreement, or a waiver of a breach hereof, must be in writing and signed by both Parties to be effective. Any waiver of a breach of this Confidentiality Agreement, whether express or implied, shall not constitute a waiver of a subsequent breach hereof.

### 13. Binding Nature and Amendment

This Confidentiality Agreement contains the entire understanding between the Parties with respect to Confidential Information received hereunder. No change or modification shall be effective unless made in writing and signed by an authorized representative of each Party. Any conflict between the language of any legend or stamp on any Confidential Information received hereunder, any provision of the Protocol, or Agreement relating to Confidential Information provided during the term of the Agreement, on the one hand, and this Confidentiality Agreement, on the other hand, shall be resolved in favor of the language of this Confidentiality Agreement. This Confidentiality Agreement may not be amended or modified except by a written agreement executed by both Parties.

### 14. Governing Law and Jurisdiction

THIS CONFIDENTIALITY AGREEMENT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF CALIFORNIA. THE PARTIES AGREE THAT ANY ACTION OR PROCEEDING ARISING OUT OF OR RELATED IN ANY WAY TO THIS CONFIDENTIALITY AGREEMENT SHALL BE BROUGHT SOLELY IN A COURT OF COMPETENT JURISDICTION SITTING IN THE CITY AND COUNTY OF SAN FRANCISCO. THE PARTIES HEREBY IRREVOCABLY AND UNCONDITIONALLY CONSENT TO THE JURISDICTION OF ANY SUCH COURT AND HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVE ANY DEFENSE OF AN INCONVENIENT FORUM TO THE MAINTENANCE OF ANY ACTION OR PROCEEDING IN ANY SUCH COURT, ANY OBJECTION TO VENUE WITH RESPECT TO ANY SUCH ACTION OR PROCEEDING AND ANY RIGHT OF JURISDICTION ON ACCOUNT OF THE PLACE OF RESIDENCE OR DOMICILE OF ANY PARTY THERETO. THE PARTIES HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVE THE RIGHT TO A JURY TRIAL IN CONNECTION WITH ANY CLAIM ARISING OUT OF OR RELATED TO THIS CONFIDENTIALITY AGREEMENT.

### 15. Severability

If any provision hereof is unenforceable or invalid, it shall be given effect to the extent it may be enforceable or valid, and such unenforceability or invalidity shall not affect the enforceability or validity of any other provision of this Confidentiality Agreement.

### 16. Notice

Any notice given hereunder by either Party shall be made in writing and shall be effective once delivered, by any of the following means:(a) facsimile or e-mail, with indication of complete electronic transmission thereof and receipt of a copy sent via certified U.S. Mail, return receipt requested, as evidenced by a signed delivery receipt; or (b) overnight delivery by a nationally recognized overnight delivery service, as verified by a delivery receipt or signature, addressed as follows:

To Participant: At the name, address and email as indicated in Participant's Offer to PG&E. To PG&E:

Pacific Gas and Electric Company
Electric Supply Department
Attn: IDER Manager
77 Beale Street, (MC B25J)
San Francisco, California 94105
Facsimile: (415) 973-3946
Email: IDERRFO@pge.com.

Either Party may periodically change any address to which notice is to be given it by providing written notice of such change to the other Party.

IN WITNESS WHEREOF, each Party has acknowledged and accepted this Confidentiality Agreement as of the Execution Date by Participant accepting its Shortlist status and by PG&E providing to Participant the Shortlist notification.

Advice 5096-E

June 16, 2017

# Attachment J4

Appendix D - Term Sheet for IDER Incentive Pilot

**Appendix D**

**Term Sheet for IDER Incentive Pilot**

| | | |
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| 1. | Project | All units, together with all appurtenant facilities and equipment, including any control and communications systems, necessary to provide Distribution Services. Units must be a distributed energy resource, and may be any technology, including energy efficiency, demand response, energy storage, ar distributed generation and may be in front of or behind the Project's retail meter. |
| 2. | Transaction | The Distribution Services provider ("Seller") shall sell and deliver, and Pacific Gas and Electric Company ("Buyer") shall purchase and receive, Distribution Services at the Contract Capacity from the Project. Seller may sell other products, including Distribution Services in excess of the Contract Capacity, to third parties or into the applicable market. Seller shall receive and retain any revenues from the sale of other products.<br><br>Seller may not provide Distribution Services from a source other than the Project. At Buyer's request, Seller shall provide to Buyer all information and data necessary to confirm that Seller delivered the Distribution Services from the Project. |
| 3. | Distribution Services | The Project's ability to provide distribution load capacity by decreasing net loading on distribution infrastructure through decreasing electrical consumption or increasing generation, in accordance with the Operating Parameters to reduce thermal overload conditions and improve local distribution reliability and resiliency. |
| 4. | Contract Capacity | Distribution load capacity: [•] MW ***[Seller to designate]*** |
| 5. | Contract Price | Capacity Price = [•] $/kw-month ***[Seller to designate]***<br>VOM = [•] $/kwh ***[Seller to designate]*** |
| 6. | Operating Parameters | The Operating Parameters of the Project are:<br><br>***For distribution load capacity:***<br><br>Delivery Months:<br>• June, July, August, September and October<br><br>Delivery Days:<br>• Every day of the week<br><br>Delivery Hours: ***[Seller to designate block of hours]***<br>• [ ] 3:00 pm to 6:00 pm<br>• [ ] 6:00 pm to 9:00 pm<br>• [ ] 3:00 pm to 9:00 p.m. |

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| | | Minimum duration the Project must be able to deliver: ***[Seller to designate based on Delivery Hours]***<br>• [3 / 6] hours<br><br>***The Project must not increase net loading on the specified circuits in Section 13 during the following periods ("Restricted Periods"):***<br><br>No Increase in net loading:<br>• 3:00 pm to 9:00 p.m., June, July, August, September, and October on days when Distribution Services are dispatched |
| 7. | Scheduling | ***For Projects that are capable of responding to a dispatch instruction:***<br><br>Buyer may dispatch the Project to deliver Distribution Services up to the Contract Capacity on a day-ahead basis. Buyer will provide a dispatch instruction to Seller by 8:00 a.m. PPT the day before a dispatch in a manner to be determined by Buyer in its sole discretion, which may include verbal or electronic notification. Seller shall, at its own cost, install all equipment and communications systems necessary to implement and respond to Buyer's dispatch instruction.<br><br>***For Projects that are not capable of responding to a dispatch instruction:***<br><br>[For purposes of calculating the Project's Distribution Services Factor in the Monthly Payment, Buyer will provide notice to Seller by 8:00 am PPT the day before Buyer requires Distribution Services of the amount of Distribution Services required, up to the Contract Capacity. |
| 8. | Communications Systems and Equipment | Seller shall install communications systems and equipment for the Project to enable Buyer to remotely monitor the status of the Project at all times during the Delivery Term on an aggregate and individual unit basis, and which permits Buyer to have real time information access to the operations of the Project, including the ability to measure the real time load decrease and/or increase.<br><br>In the event that during the term of the agreement, Buyer develops its own system that allows Buyer to exercise greater monitoring or more efficient dispatch of the Project, Seller shall enable its equipment and system to interface with Buyer's system such that Buyer may monitor and dispatch the Project through Buyer's system. |
| 9. | Restricted Periods | Within Seller's monthly invoice, Seller shall submit to Buyer an attestation stating that the Project did not increase or reduce net loading on the specified circuits during the Restricted Periods for that month. |

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| 10. | Failure to Comply with Restricted Periods | For each day the Project increases or reduces net loading on the specified circuits during a Restricted Period, Seller will pay Buyer the product of (a) the maximum amount of kW that the Project increased/decreased load for that day, multiplied by (b) the ratio of (i) the then highest monthly Contract Price for the calendar year, divided by (ii) the number of days in the applicable month. |
| 11. | Operational Control | Notwithstanding Seller's obligations to deliver Distribution Services, Seller will have operational control of the Project and be responsible for operation and maintenance of the Project. Buyer will not bear any costs related to ownership, operation, scheduling, dispatch, or maintenance of the Project. |
| 12. | Project Site and Customers | Seller shall execute all necessary forms, documentation, and agreements in order to secure all Sites and/or Customers necessary to deliver Distribution Services to Buyer. The terms and conditions of the agreements Seller has for the Site and/or with Customers are independent of Buyer, and Buyer shall not have any responsibility or incur any liability pursuant to such agreements.<br><br>At any time during the Delivery Term, Seller may remove, replace, or add any unit associated with a Site/Customer, provided that any such change shall not modify the Distribution Services, and provided further that any such change shall be made in accordance with the safety provisions of the agreement.<br><br>Prior to the Initial Delivery Date, Seller shall provide Buyer a list identifying all Sites and Customers comprising the Project that may deliver Distribution Services. For each Site/Customer, Seller must satisfy the criteria of incrementality and meet the measurement and verification requirements for such Site or Customer. Buyer will verify with Seller which Sites/Customers are eligible to deliver Distribution Services prior to the Initial Delivery Date.<br><br>During the Delivery Term, no less than 15 days prior to a Delivery Month, Seller will provide Buyer an updated Site/Customer list if any Customers comprising the Project change. For each updated Site/Customer, Seller must satisfy the criteria of incrementality and meet the measurement and verification requirements for such Site or Customer. No less than 5 days prior to a Delivery Month, Buyer will verify with Seller whether the updated Sites/Customers are eligible to deliver Distribution Services.<br><br>Any and all marketing materials developed by Seller that reference Buyer will be subject to prior written approval by Buyer. Seller is responsible for all marketing activities to Customers, provided that Buyer will provide [0, 50, 200] ***[Seller to designate]*** hours of customer representative time to aid in making introductions for Seller's purpose of customer acquisition. |

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| 13. | Interconnection | The Project is interconnected to circuits or loads or associated with load facilities that are electrically interconnected to one of the following feeders at the Rincon substation:<br><br>• Rincon 1105 Rincon 1101<br>• Rincon 1103 Rincon 1104<br><br>Seller shall interconnect the Project in accordance with the requirements and terms and conditions set forth in the Utility Distribution Company's applicable tariffs, and if applicable, the Participating Transmission Owner's applicable tariffs and the CAISO tariff, in order to safely and reliably deliver Distribution Services to Buyer. Seller shall be responsible for all delays, costs and expenses associated with such interconnection. |
| 14. | Initial Delivery Date (IDD) | ***[Seller to designate]***<br>[June 1, 2020, June 1, 2021 or June 1, 2022]. Failure to meet the Initial Delivery Date will be an Event of Default. |
| 15. | Delivery Term | The Delivery Term will be [3 / 5] [***Seller to designate***] years from the Initial Delivery Date. |
| 16. | Critical Milestones | Seller shall cause the development and construction of the Project to meet each of the following ("Critical Milestones)" by the date set forth: [***Seller to designate milestone dates***]<br><br>(i) 50% of Customer acquisitions:<br><br>(ii) 75% of Customer acquisitions<br><br>(iii) 100% of Customer acquisitions:<br><br>(iv) Site control:<br><br>(v) Execution of interconnection agreement(s):<br><br>(vi) Construction start:<br><br>(vii) Commercial Operation Date:<br><br>(viii) Initial Performance Test:<br><br>Missing a Critical Milestone will be considered an Event of Default |
| 17. | Compensation | Buyer shall pay to Seller a monthly payment for the Distribution Services in each of the [Delivery Months]: |

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<tr>
<td></td>
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<td>
MPm = FPm + VPm<br><br>
where<br><br>
MPm = Monthly Payment for Delivery Month m<br>
FPm = Fixed Payment for Delivery Month m<br>
VPm = Variable Payment for Delivery Month m<br><br>
Fixed Payment<br><br>
FPm = CCm x CPm x DSFm<br><br>
where<br><br>
CCm = Contract Capacity for Delivery Month m<br>
CPm = Capacity Price for Delivery Month m<br>
DSFm = Distribution Services Factor for Delivery Month m, based on the ratio of<br>
∑ DSPi / ∑ DSEi), where:<br><br>
∑ = the sum from i = 1 to n, where n = number of times Buyer requires Distribution Services for a Delivery Month;<br>
DSPi = the amount of Distribution Services delivered by Seller in response to Buyer’s dispatch or notification i;<br>
DSEi = the amount of Distribution Services Buyer requires for each dispatch or notification i ;<br><br>
<table>
<tr><td>Ratio</td><td>DCF</td></tr>
<tr><td>≥1.00</td><td>100%</td></tr>
<tr><td>≥0.90 and < 1.00</td><td>Ratio</td></tr>
<tr><td>≥0.80 and < 0.90</td><td>Ratio x 50%</td></tr>
<tr><td>≥0.75 and < 0.80</td><td>0</td></tr>
<tr><td>< 0.75</td><td>Ratio – 0.75 (Seller will pay Buyer)</td></tr>
</table>
<br>
Variable Payment<br><br>
VPm = ∑ min (DSPi, DSEi) x VOMm<br><br>
where<br><br>
VOMm = Variable Price for Delivery Month m
</td>
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<tr>
<td>18.</td>
<td>Measurement and Verification</td>
<td>
The amount of Distribution Services the Project delivers will be measured based on the Project’s technology, and will include for:<br><br>
• Energy storage: revenue-quality interval meter;
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| | | • Demand response: CAISO baseline methodologies, based on revenue-quality Customer interval meters;<br><br>• Distributed generation: revenue-quality interval meter for generation, agreed upon forecast methodology for curtailable generation; or<br><br>• Energy efficiency or permanent load shift: Parties' agreed upon methodology that incorporates metering against a baseline |
| 19. | Performance Testing | The Parties will develop mutually acceptable test procedures (Performance Test).<br><br>Prior to the Initial Delivery Date, Seller will perform an Initial Performance Test to demonstrate to Buyer that the Project is capable of delivering Distribution Services at the Contract Capacity. The Initial Performance Test may need to take into account (1) that such Initial Performance Test is occuring outside a Delivery Month and (2) the Project's ability to test alignment with the Operating Parameters given the timing and duration of the Initial Performance Test. The Initial Delivery Date will occur if Seller demonstrates the Project's delivery of Distribution Services at 100% of the Contract Capacity.<br><br>After the Initial Delivery Date, Buyer will have the right to test the Project no more than once a calendar year to ensure that the Project is capable of delivering the Distribution Services. Seller will have a right to retest once a calendar year after a Buyer Performance Test.<br><br>If a Performance Test shows the Project able to deliver Distribution Services at more than or equal to 85% of the Contract Capacity, but unable to deliver Distribution Services at 99% of the Contract Capacity, the Contract Capacity will be automatically reduced to the amount of Distribution Services the Project delivered in the Performance Test. |
| 20. | Seller Performance Assurance | Seller shall deliver to Buyer and maintain Performance Assurance in a form acceptable to Buyer to secure its obligations under the agreement, as follows:<br><br>(i) Project Development Security. Seller shall post Project Development Security in the form of cash or letter of credit, equal to (i) $60/kW for new Projects or (ii) $25/kW for existing Projects.<br><br>(ii) Prior to IDD, Seller shall post Delivery Term Security in the form of cash or letter of credit, in an amount equal to the maximum of (i) $125/kW and (ii) 10% of the sum of the highest Fixed Payments for any 36-month period during the Delivery Term. Seller may apply the Project Development Security toward the Delivery Term Security. |

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| 21. | Events of Default | Customary provisions similar to a PG&E PPA or Capacity Storage Agreement in 2016 Energy Storage RFO and will also include the following Seller Events of Default:<br><br>(i) Failure to meet a Critical Milestone<br><br>(ii) Failure to meet Initial Delivery Date<br><br>(iii) The monthly Distribution Services Factor for any calendar year averages less than 75%<br><br>(iv) Results of a Performance Test show that the Project provides Distribution Services at less than 85% of the Contract Capacity<br><br>(v) Seller operates during the Restricted Period more than 3 days in a calendar year |
| 22. | Force Majeure | Customary provisions similar to a PG&E PPA or Capacity Storage Agreement in 2016 Energy Storage RFO. In addition, inability to obtain or retain the Site and/or Customers is not an event of force majeure. |
| 23. | Termination Payment | In an Event of Default, the Non-Defaulting Party has the right to terminate this agreement, whereby the Defaulting Party will owe the Non-Defaulting Party a Termination Payment. The Termination Payment will be equal to the Project Development Security if such termination occurs prior to the Initial Delivery Date and equal to the Delivery Term Security if such termination occurs after the Initial Delivery Date. |
| 24. | Safety | Seller will be required to meet certain safety standards with respect to the Project. Seller's safety obligations will reflect the agreement and Project structure, technology, and Distribution Services along with Seller's commercial relationship with the Site(s) and Customers. |
| 25. | CPUC Approval | If CPUC Approval has not occurred on or before 180 days from the date on which Buyer files the agreement with the CPUC seeking CPUC Approval, then either Party may terminate the agreement.<br><br>"CPUC Approval" means a final and non-appealable order of the CPUC, without conditions or modifications unacceptable to either of the Parties, pursuant to which the CPUC approves of this agreement in its entirety. |
| 26. | Conditions Precedent | Customary provisions similar to a PG&E PPA or Capacity Storage Agreement in 2016 Energy Storage RFO, and will also include the following:<br><br>The Initial Delivery Date shall not occur until Seller:<br><br>(i) has constructed the Project and provided certification from an |

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| | | independent engineer that the Project is Commercially Operable and constructed in accordance with the safety requirements;<br><br>(ii) has demonstrated in the Initial Performance Test that the Project is capable of delivering Distribution Services at the level set forth in Section 19; and<br><br>(iii) has provided Buyer with a list of Site(s) and Customers comprising the Project and Buyer has verified that such Sites/Customers are incremental and eligible to provide Distribution Services. |
| 27. | Confidentiality | Customary provisions similar to a PG&E PPA or Capacity Storage Agreement in 2016 Energy Storage RFO. |
| 28. | Dispute Resolution | Customary provisions similar to a PG&E PPA or Capacity Storage Agreement in 2016 Energy Storage RFO. |
| 29. | Governing Law | California |

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# Attachment J5

Appendix E – Finance Information

## Finance Information

**Participant Name:**

Provide the following information for assessment of the financial viability of Participant. Include additional sheets and other materials with this Appendix as necessary. Financial information must be provided for the Participant and any entity providing credit enhancement or other corporate support to the Participant. As necessary, please specify whether the information provided is for the Participant, its parent or affiliate, or an entity providing security on the Participant's behalf. All capitalized terms not defined herein, shall have the meaning provided in the RFO.

### Participant Financial Information

1. If available, provide three years of audited financial statements and year-to-date financial statements of Participant and/or guarantor.

In conformity with Generally Accepted Accounting Principles ("US GAAP") PG&E may be required to collect and possibly consolidate financial information from the facility, whose output is being purchased under long-term contractual arrangements. Some general guidelines for determining whether consolidation must occur include:

1) Determination of allocation of the entity's risks and rewards;

2) Proportion of expected project life being committed to PG&E; and

3) Pricing provisions of contract. That is, does the contract contain fixed long-term prices or does pricing vary over the term of the agreement based on market conditions or other factors.

For any Agreement that meets the applicability criteria as established by US GAAP, PG&E is obligated to obtain information from successful Participants to determine whether or not consolidation of a counterparty's financial information is required.

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# Attachment K

Forecast of Expected Incremental Administrative Costs and Preliminary Estimate of Cost Effectiveness Cap

(Confidential )

**PG&E Gas and Electric**
**Advice Filing List**
**General Order 96-B, Section IV**

AT&T
Albion Power Company
Alcantar & Kahl LLP
Anderson & Poole
Atlas ReFuel
BART
Barkovich & Yap, Inc.
Bartle Wells Associates
Braun Blaising McLaughlin & Smith, P.C.
Braun Blaising McLaughlin, P.C.
CENERGY POWER
CPUC
CalCom Solar
California Cotton Ginners & Growers Assn
California Energy Commission
California Public Utilities Commission
California State Association of Counties
Calpine
Casner, Steve
Center for Biological Diversity
City of Palo Alto
City of San Jose
Clean Power
Clean Power Research
Coast Economic Consulting
Commercial Energy
Cool Earth Solar, Inc.
County of Tehama - Department of Public Works
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy
Defense Energy Support Center
Dept of General Services

Division of Ratepayer Advocates
Don Pickett & Associates, Inc.
Douglass & Liddell
Downey & Brand
Ellison Schneider & Harris LLP
Evaluation + Strategy for Social Innovation
G. A. Krause & Assoc.
GenOn Energy Inc.
GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Charge Networks
Green Power Institute
Hanna & Morton
ICF
International Power Technology
Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Leviton Manufacturing Co., Inc.
Linde
Los Angeles County Integrated Waste Management Task Force
Los Angeles Dept of Water & Power
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenna Long & Aldridge LLP
McKenzie & Associates
Modesto Irrigation District
Morgan Stanley
NLine Energy, Inc.
NRG Solar
Nexant, Inc.
ORA
Office of Ratepayer Advocates

Office of Ratepayer Advocates, Electricity Planning and Policy B
OnGrid Solar
Pacific Gas and Electric Company
Praxair
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions
SCE
SDG&E and SoCalGas
SPURR
San Francisco Water Power and Sewer
Seattle City Light
Sempra Energy (Socal Gas)
Sempra Utilities
SoCalGas
Southern California Edison Company
Southern California Gas Company (SoCalGas)
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
TerraVerde Renewable Partners
TerraVerde Renewable Partners, LLC
Tiger Natural Gas, Inc.
TransCanada
Troutman Sanders LLP
Utility Cost Management
Utility Power Solutions
Utility Specialists
Verizon
Water and Energy Consulting
Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
YEP Energy
Yelp Energy