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BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769. (U39E)	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters.	A.15-07-002 A.15-07-003 A.15-07-006

(NOT CONSOLIDATED)

In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	A.15-07-005 (Filed July 1, 2015)
And Related Matters.	A.15-07-007 A.15-07-008

REVISED TRACK 2 DEMONSTRATION PROJECT PROPOSALS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) PURSUANT TO MAY 17, 2016, JOINT ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE'S RULING

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Attorney for
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Dated: June 17, 2016

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REVISED TRACK 2 DEMONSTRATION PROJECT PROPOSALS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) PURSUANT TO MAY 17, 2016, JOINT ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE'S RULING

Pursuant to the May 17, 2016, Joint Assigned Commissioner and Administrative Law Judge's Ruling Regarding Track 2 Demonstration Projects in this proceeding (May 17 ACR), Pacific Gas and Electric Company (PG&E) provides its revised proposals for Track 2 Demonstration Projects and responses to questions in the May 17 ACR.

PG&E's revised Track 2 Demonstration Project proposals are provided in Attachment 1.

Respectfully submitted,

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Attachment 1

Answers to Questions for PG&E's Revised Track 2 Demonstration Project Proposals

1. Introduction and Background

PG&E's Distribution Resources Plan (DRP) Demonstration projects[1] are an essential element of realizing PG&E's DRP vision, because they will provide opportunities to test new technologies, planning processes, and operational practices. The DRP demonstration projects will draw on learnings from PG&E's Smart Grid activities, EPIC-funded projects, experience implementing customer programs, and wholesale market activities to bring multiple elements together in three real-world deferral opportunities for conventional distribution investments. Through these pilots, we will gain the data and experience that will be fundamental to upcoming efforts to enhance planning practices and DER valuation and compensation methodologies.

In this context, PG&E submits revised proposals for its Demonstration Projects C, D and E. These revisions add specificity to the projects originally proposed in 2015 and address questions posed by the CPUC. Learnings from the pilots will be documented through data collection and public reporting and will inform planning to scale best practices system-wide.

As discussed in more detail below in the Budget and Cost Recovery sections for each Project, PG&E requests Commission authorization to recover from customers the revenue requirements necessary to fund the estimated costs of the Projects, which total approximately $8.05 million for the program administration costs, and additional costs of DER procurement that will be determined in a competitive solicitation for DER services for each project. The DRP Demonstration Program costs include incremental capital and expenses related to the program, DER procurement costs, associated operations and maintenance (O&M) costs, program management costs and other administrative and general (A&G) costs, and similar costs of the Program over the term of the Program.

For recovery of the incremental costs associated with its DRP Demonstration Program, PG&E requests that the Commission authorize PG&E to include in electric distribution rates the forecast revenue requirements associated with the demonstration projects described below beginning January 1, 2017. PG&E requests that the Commission authorize PG&E to establish the Distribution Resources Plan Demonstration Program Balancing Account (DRPDPBA), which is a one-way balancing account, to record and track the authorized revenue requirements compared to the revenue requirements

[1] PG&E's DRP application, A.15-07-006, described the demonstration projects that PG&E proposes to conduct to demonstrate its enhanced distribution planning methodologies before applying those methodologies on a system wide basis.

associated with actual costs, including expense and capital. Upon conclusion of the Projects, any unspent funding in the tracking account would be returned to customers by transferring the balance to the Distribution Revenue Adjustment Mechanism (DRAM) as part of PG&E's Annual Electric True-up (AET) process. A pro-forma preliminary statement for the DRPDPBA is attached.

The scope, schedule and estimated costs of the Program described below are subject to change based on comments from interested parties and approval by the Commission.

COMMISSION APPROVAL

1. Should any of the demonstration projects, either as a category across all utilities or for a specific utility, be prioritized for Commission approval, or should all projects be approved at the same time? Explain the reasons. Are there specific timing considerations that should be factored?

PG&E requests that the Commission approve all of its proposed Track 2 Demonstration Projects, including the revenue requirements and cost recovery required to fund the projects, as soon as possible to allow implementation activities to begin and ensure timely completion of distribution upgrades identified as needed to meet PG&E's safety and reliability standards at each of the proposed demonstration project locations.

Each of the proposed demonstration locations was selected to showcase the integration of DERs into planning and operations in addressing projected distribution grid needs at the specific locations, such as demonstrating distribution capacity to serve load, host additional DERs, and provide reliable electric service. However, due to the timing of these projected distribution grid needs for these demonstration locations, with some locations projected to experience distribution capacity deficiencies as early as 2018, the Commission must approve the demonstration projects at these locations no later than August 2016 to allow for timely planning and implementation to meet the grid needs.

2. Project C

OBJECTIVES AND METHODS

1. ***Describe the project goals and the specific functions and features of DERs the project will demonstrate. Describe how the projects will demonstrate the stated goals found in the description of the demonstration project at pages 6-7 of the Attachment to the Guidance Ruling dated February 2, 2015.***

   The project goals as well as specific functions and features of DERs the project will demonstrate are summarized below:

   - Project Goals: To validate, through commercial scale field deployment, the ability of DERs to achieve net benefits consistent with the indicative Locational Net Benefit Analysis for three or more types of benefits. In order to validate the ability of DERs to achieve net positive benefits, the focus of the demonstration project will be to reduce distribution system costs by deferring planned distribution capacity work for a minimum of 3 years by deploying DER alternatives. In addition, this project will demonstrate the ability of deployed DERs to reduce other utility costs consistent with the indicative avoided costs estimated by the Locational Net Benefit Analysis tool.

   - DER Functions: Demonstrate that a DER portfolio can effectively provide safe and reliable distribution services via coordinated DER dispatch/ scheduling or with non-dispatchable DERs that have loading profiles that reduce the local peak demand to levels that address projected distribution capacity deficiencies.

   - DER Features: To demonstrate the operations of multiple DER types in concert, and to show how a least-cost/best-fit DER portfolio can be constructed through a competitive solicitation using locational factors such as load characteristics, customer mix, building characteristics and the like.

2. ***What are the specific learning objectives and how will that inform the achievement of California's DRP Goals?***

   The specific learning objectives of this demonstration include: 1) Sourcing of a localized DER portfolio via competitive solicitation; 2) Administration and operation of a localized DER program by the utility, 3) Validation of DER distribution service capabilities, and 4) Validation of locational net benefits as estimated by the indicative Locational Net Benefits Analysis (LNBA) model in DRP Demonstration Project B.

   Sourcing of a Localized DER Portfolio via a Competitive Solicitation:

   PG&E will gain more knowledge and experience on how to construct least cost best fit DER portfolios based on locational factors. PG&E plans to conduct a competitive solicitation to procure a localized DER portfolio and gain more knowledge and experience on developing and implementing a solicitation for DER resources to address local distribution needs.

Administration and Operation of a Localized DER Program

PG&E proposes to demonstrate that a localized DER portfolio that is sourced through a competitive solicitation can be administered and operated on an ongoing basis by the utility as a DER program. Specifically, a DER portfolio that is comprised of a significant portion of behind the meter resources represents a commitment to ongoing customer engagement. DER program infrastructure must be developed that can ensure customers are treated in a fair and equitable manner and that deployed DERs are operated safely, reliably and consistent with the program objectives.

Additional specific learning objectives of Demonstration Project C will be to understand how a localized and ongoing customer engagement program can be structured, including in front of the meter and behind the meter resources. Utilities are familiar with administering and operating single DER customer engagement programs for single behind the meter DERs such as energy efficiency (EE) and demand response (DR). Project C will provide an opportunity to understand how single DER program structures can evolve to meet the challenge of administering a localized engagement that spans multiple DERs.

Validate DER Distribution Service Capabilities and Benefits

From an operational perspective, PG&E is seeking to obtain additional knowledge on the ability of DERs, when operated in a coordinated and aggregated manner, to provide safe and reliable distribution services, such as distribution capacity. Specifically, PG&E is seeking to better understand how a portfolio of DERs, including both in front of meter and behind the meter resources, can be operated in aggregation within a local geographical area to successfully meet the distribution grid's local needs.

Validate Locational Benefits as Estimated by LNBA Model and Costs

In addition, PG&E will seek to validate through Demonstration Project C the indicative locational benefit estimates produced by the LNBA model.

PG&E will also seek to capture DER costs, deferred conventional investments, and any additional costs associated with deployment and management of the DER portfolio.

3. ***What specific metrics will assess the project performance?***

Overall, Project C is meant to demonstrate the ability of DERs to achieve net benefits consistent with the locational net benefits methodology. The following metrics will assess project performance:

- Distribution Services Effectiveness – Measure the effectiveness of coordinated DER dispatch/scheduling to provide distribution services, such as mitigating projected equipment overloads on the distribution grid. Comparative analysis will be performed evaluating projected equipment loading levels against actual equipment loading levels. Specifically, this evaluation will compare equipment loadings "before" and "after" the sourced DERs are dispatched to understand the technical effectiveness of the sourced DERs.
  - Example data that would be needed to develop metrics: Circuit simulation data, SCADA data, Smart meter data, DER operational data, etc.

- DER Readiness & Assurance – Measuring the time between contract award to operation to ensure timeliness in meeting the locational needs. Ensure that DER readiness is available when expected to contribute to the grid needs and utility reserved periods pending contract arrangements.
  - Example data that would be needed to develop metrics: DER dispatch response time, Costs and schedules to complete DER siting and operation, etc.

- LNBA Validation - An evaluation, measurement and verification (EM&V) study performed by a third party expert to be made public suggesting enhancements to the LNBA model estimates that address any identified gaps between estimated LNBA and the observed results from Project C.
  - Example data that would be needed to develop metrics: Interconnection Capacity Analysis, daily load/generation profiles, etc.

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

4. ***What is the project's potential for replication across the system?***

The findings from this project will help PG&E prioritize operational approaches, portfolios of complementary DERs, or other methods to minimize disruptive effects.

PROJECT LOCATION

5. Identify the proposed location for the project and explain why the location was selected.

PG&E's DRP filing identified the Central Fresno Distribution Planning Area (DPA) location for validating the ability of DERs to achieve net benefits consistent with the Optimal Location Benefit Analysis, where DERs will either displace or operate in concert with existing infrastructure to provide defined functions. This demonstration also required that at least three avoided cost categories or services be demonstrated to validate net benefits. This area was initially selected for Demonstration C due to various factors that made this location and attractive location to test the LNBA methodology. These factors included: increasing customer demand, projected distribution capacity needs and coordination with other pilot projects, such as the Volt/Var Optimization (VVO) Pilot project.

However, according to recent analysis of this area, the Central Fresno DPA is not projected to experience increasing customer demand, in large part due to the absence of new development driven by lower than expected regional economic growth. As a result, projected distribution capacity needs with the next five years have been extended beyond 8 years, which made this location infeasible for Demonstration C.

PG&E has identified an alternate location for Demonstration C. This alternate location is projected to require various distribution capacity upgrades that may be deferred with cost effective DERs. This location is further described below.

Chico 12 kilovolt (kV) DPA (Chico DPA)

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

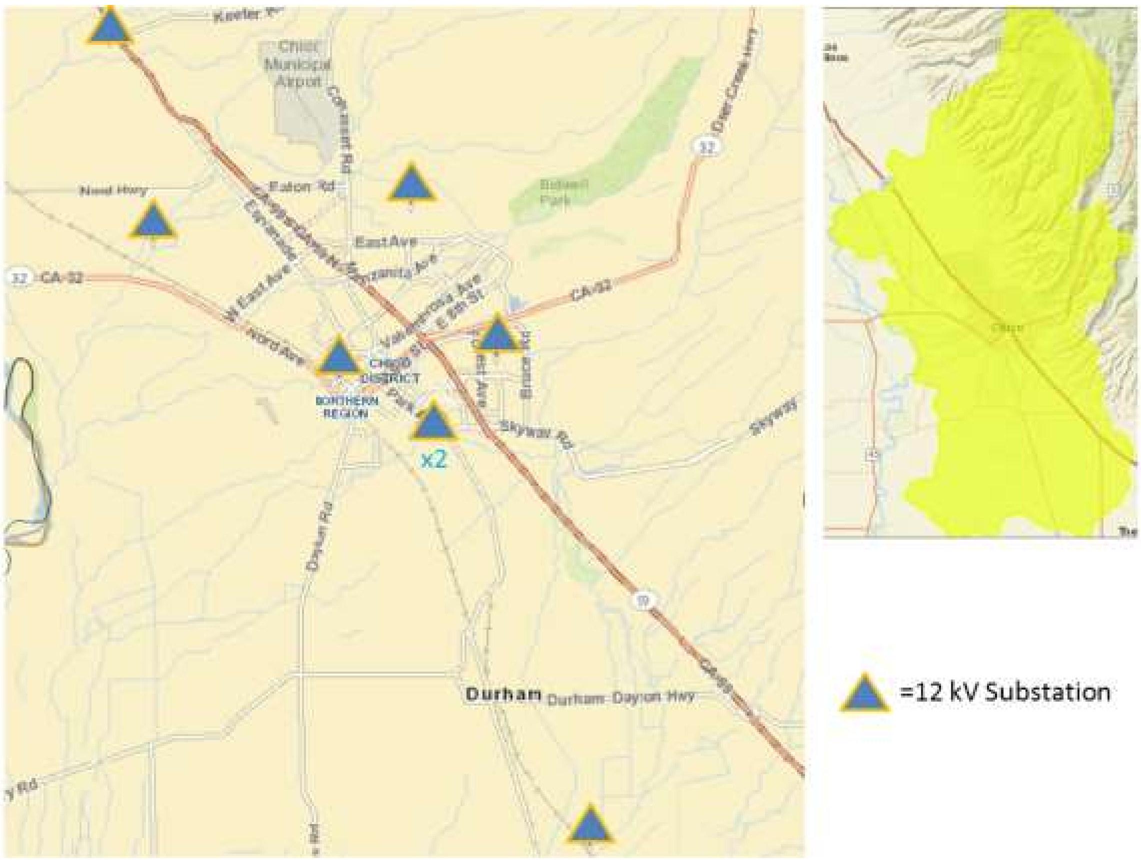

Figure 1: Map of Chico 12 kV DPA

Furthermore, additional review of the Chico DPA has determined that this area can support the deployment of a diversified DER portfolio, which could provide potential opportunities of validating avoided cost benefits such as deferred distribution capacity, reduced resource adequacy requirements and reduced flexible capacity requirements.

6. ***Identify the relevant characteristics of the location chosen for the project (e.g., rural or urban area, current load, number of customers, current DER penetration, and projections of load and DER penetration).***

The following table summarizes relevant characteristics of the Chico DPA.

Table 1: Chico 12 kV DPA Characteristics

Geographical Density	2015 Observed Peak Load	Number of Customers	Current DG Penetration	Load Projection	DG Penetration Projection
Urban	236 MW	125,000	38 MW	2017: 249 MW 2018: 256 MW 2019: 264 MW 2020: 270 MW 2021: 276 MW	2017: 43 MW 2018: 47 MW 2019: 51 MW 2020: 55 MW 2021: 59 MW

7. ***Describe any relevant demonstration projects and pilots being done outside of the DRP process (for example, with EVs and the demand response reverse auction) and the coordination issues that need to be considered.***

   The Chico DPA is one of the areas where PG&E is actively investigating the feasibility of deploying a Targeted Demand Side Management (TDSM) solution. PG&E's TDSM initiative is administered outside of the DRP process. PG&E has performed an initial review of TDSM feasibility for this area and has determined that there is a high potential for a portfolio of DERs to address the projected distribution capacity needs. This review has identified, for example, that there are significant residential SmartAC direct load control resources already deployed in the Chico DPA that could be configured to support local area reliability, there also is a high potential for increasing residential DR resources in the area. Currently there is a fair amount of distributed generation (DG) resources already deployed in the area, with high potential for additional DG growth in the future. In addition there is high potential for targeted EE to reduce distribution capacity needs in the area over the next several years.

   This project will test the ability of portfolios composed of these, and/or other, DERs to provide the system benefits predicted by PG&E's LNBA methodology.

DER PORTFOLIO and DER OWNERSHIP

8. ***If known, explain what specific DER technologies will be selected and why.***

   The exact composition of DER technologies that will be selected at this time is unknown. PG&E proposes to conduct an all-source competitive solicitation in the area to seek bids from a variety of DER providers including EE, DR, DG, EV and Energy Storage (ES) located either in front of the customer meter or behind the customer meter. These DERs sourced via competitive solicitation may be complimented by existing DERs that have been deployed in the demonstration project area through customer funded voluntary incentive programs. The issue of "incrementality" – how competitively sourced DERs compliment or duplicate DERs sourced through existing voluntary incentive programs – is currently being addressed in the Competitive Solicitations Framework Working Group.

9. ***Describe what role third-party DER technology vendors will have in the project.***

   As noted in response to question 8, it is PG&E's intention to conduct an all-source competitive solicitation to source the DER technologies that will meet the objectives of Project C. Third-party DER technology vendors will be the focus of that solicitation.

10. ***Describe DER ownership: utility, customer, and third party with appropriate justification.***

PG&E envisions that the all-source competitive solicitation will allow DER technology vendors to propose and price various ownership structures. PG&E will select DERs that represent a least-cost/best-fit outcome, which may incorporate elements of utility, customer, and/or third party ownership. PG&E is open to consider a range of approaches to ensure operational reliability potentially including contractual provisions, automated control systems, or direct utility ownership of DER equipment.

As described in the response to Question 2, one of the learning objectives of Demonstration Project C is to gain more experience and knowledge on whether a DER portfolio is feasible to meet the needs for which it was procured.

BUDGET AND COST RECOVERY

11. ***Provide a breakdown of the project by activity (e.g., engineering, installation of field devices, modeling, data gathering, data analysis) and an estimated cost for each activity. Include the grand total for the project.***

The following table summarizes the proposed work scope/activity items, schedule and preliminary budget of each work scope/activity. PG&E requests Commission authorization to recover from customers the revenue requirements necessary to fund the estimated program administration costs of the Project listed below, and to recover the additional costs of DER procurement that will be determined in a competitive solicitation for DER services for each project.

Table 2: Demonstration Project Breakdown by Scope, Schedule and Preliminary Budget

Milestone No.	Work Scope/Activity	Category	Schedule (days are additive)	Preliminary Budget
0	CPUC Decision Approving Demos C, D and E, including cost recovery		August, 2016 (if decision is later, project viability and schedule may change)	
1	Develop Competitive Solicitation Materials and Launch/Issue Solicitation	Pre-Solicitation	60 days from CPUC Approval	$300,000
2	After Solicitation Issuance: - Respond to developer questions - Participant's Conference, if needed	Administer Solicitation		$950,000
3	Offers Received		+ 60 days	
4	Offer Evaluation - Process and Evaluate Offers - Develop Shortlist/Preferred offers		+ 90 days	

Milestone No.	Work Scope/Activity	Category	Schedule (days are additive)	Preliminary Budget
5	Negotiate and execute agreements with preferred offers		+ 180 days	
6	Prepare for CPUC Approval of DER agreements from solicitation		+ 60 days	
7	CPUC Approves DER Agreement(s) and Agreement(s) now effective		+ 90 days	
8	Final Design Completed	Project Construction	+ 90 days	$500,000
9	Construction Completed		+ 180 days	
10	Acceptance Testing Completed		+ 14 days	
11	Demonstration Project Released for Operation		+ 14 days	
12	Post Demonstration Project EM&V (e.g. data gathering and analysis)	Demonstration Results	+ 365 days	$100,000
13	Post Demonstration Project Process Report		+ 90 days	$200,000
Total				**$1,750,000 + DER Procurement Cost**

12. What other funding and/or pilots will be leveraged by deploying the project in the proposed area?

Demonstration Project C may be able to leverage PG&E's ongoing TDSM initiative and program coordination funds through existing Energy Efficiency Programs funding. However, any use of existing funding and/or pilots must be consistent with the goals and key learning objectives for Project C described in response to questions 1 and 2.

SCHEDULE

13. Provide a schedule for project design and deployment. Identify major milestones for the project and a description of the activity to be performed. Include a timetable (by year and quarter) showing when each step will be completed, including when deliverables are due.

See the response to Question 11 for Demonstration Project C.

DELIVERABLES AND REPORTING

14. Identify the deliverables that are expected during the project including their due dates.

In addition to the milestones and deliverables that are listed in the response to question 11, PG&E also proposes to provide a more refined project implementation plan, including work scope, schedule and budget. PG&E plans to provide this refined implementation with 90 days following Commission approval of the Demonstration Project.

15. Identify a schedule and format for reporting to the Commission interim and final results.

In addition to the final report listed in the response to question 11, PG&E plans to provide an interim progress report to the Commission documenting the progress of this demonstration, as well as the stakeholder feedback received and actions taken to further this demonstration. The interim progress report would be submitted one year after Commission approval of the Demonstration Project.

STAKEHOLDER ENGAGEMENT AND COLLABORATION WITH THIRD-PARTIES

16. How will stakeholder participation be coordinated in the design and implementation of the project?

PG&E proposes to host quarterly meetings and reporting to stakeholders on all DRP Demonstration Projects. PG&E proposes to utilize similar reporting specifications as included in similar annual Smart Grid reports.

3. Project D

OBJECTIVES AND METHODS

1. ***Describe the project goals and the specific functions and features of DERs the project will demonstrate. Describe how the projects will demonstrate the stated goals found in the description of the demonstration project at pages 6-7 of the Attachment to the Guidance Ruling dated February 2, 2015.***

   The project goals as well as specific functions and features of DERs the project will demonstrate are summarized below:

   - Project Goals: To demonstrate effective distribution planning and operations for high amounts of DER penetrations. PG&E plans to monitor and control DER resources using various ownership and control structures to provide locational value and defer capital investments. Effectiveness will be determined by how DERs can provide distribution services around dynamically increasing DER hosting capacity for periods of high DER output conditions and distribution capacity services for periods of high demand periods.

   - DER Functions: Demonstrate that a cost effective DER portfolio can safely and reliably provide multiple distribution services via coordinated DER dispatch/ scheduling to reduce thermal loadings and/or ensure service voltage levels are maintained with Rule 2 specifications.

   - DER Features: To demonstrate the operations of multiple DER types in concert under different ownership and control structures. This will show how a cost effective DER portfolio can be constructed with a fleet of DERs dispersed around the demonstration area which can be aggregated to dispatch a coordinated output. PG&E will require the ability to monitor and control fleets of DERs through universal control signals.

2. ***What are the specific learning objectives and how will that inform the achievement of California's DRP Goals?***

   The specific learning objectives of this demonstration include: 1) Competitive Solicitation of DERs, 2) Multiple Use Application of DERs 3) Operation of Aggregated Fleet of dispersed DERs.

   Sourcing of a Localized DER Portfolio via a Competitive Solicitation:

   PG&E will gain more knowledge and experience on how to construct least cost best fit DER portfolios based on locational factors. PG&E plans to conduct a competitive solicitation to procure a localized DER portfolio and gain more knowledge and experience on developing and implementing a solicitation for DER resources to address local distribution needs.

Multiple Use Application of DERs

This project will demonstrate the ability of a utility to operate DERs in a multiple use application manner where an aggregated DER portfolio may provide hosting capacity services during peak distributed generation production hours, as well as distribution capacity services during peak demand hours.

Operation of Aggregated Fleet of Dispersed DERs

This project will demonstrate the ability of a utility to operate an aggregated fleet of dispersed DERs to provide distribution services such as hosting capacity and distribution capacity services to ensure safe and reliable operation. In addition, observations and learnings will be obtained in investigating response time and dispatch accuracy against projected responses and behaviors on the grid.

3. ***What specific metrics will assess the project performance?***

The following metrics will assess project performance:

- Distribution Capacity and Hosting Capacity Service Effectiveness – Measure the technical effectiveness of DER dispatch with mitigating projected equipment overloads. Comparative analysis will be performed evaluating projected equipment loading levels against actual equipment loading levels and conditions when sourced DER portfolio is dispatched.
    - Example data that would be needed to develop metrics: Circuit simulation data, SCADA data, Smart meter data, DER operational data, etc.

- DER Readiness & Assurance – Measuring the communication reliability between PG&E dispatch operators and the aggregator owned DER equipment. Ensure that DER readiness is available when called upon during emergency services and utility reserved periods pending contract arrangements.
    - Example data that would be needed to develop metrics: DER dispatch response time, Costs and schedules to complete DER siting and operation, etc.

- Process Evaluation - A process evaluation study performed by a third party expert to be made public describing the end to end process of Project D implementation and suggesting a enhancements to the future DER deployments with similar use cases. This process evaluation will also critique and provide suggestions for improvements in the process of developing least-cost/best-fit DER portfolios and the sourcing of those portfolios.

4. ***What is the project's potential for replication across the system?***

   The findings from this project will help PG&E prioritize operational approaches, portfolios of complementary DERs, or other methods to minimize disruptive effects of high DER penetrations.

PROJECT LOCATION

5. ***Identify the proposed location for the project and explain why the location was selected.***

   The proposed location for this demonstration is PG&E's Huron Substation, which is located within PG&E's Gates DPA. Huron Substation was selected due to its high penetration of DERs against this area's distribution capacity. High penetration of DERs can lead to many possible grid issues if not addressed. These issues could be unknown thermal overloading, nuisance equipment tripping, fault miscoordination, and many more. Although many of these issues are addressed in the interconnection phase, there are some limitations that may not arise until operation.

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

   Furthermore, this area was selected due to its unique loading profile that is forecast to resemble the "duck curve" that includes high distributed generation output during peak solar production hours and high peak demand during the evening hours.

6. ***Identify the relevant characteristics of the location chosen for the project (e.g., rural or urban area, current load, number of customers, current DER penetration, and projections of load and DER penetration).***

   The following table summarizes relevant characteristics of Huron Substation.

Table 3: Huron Substation Characteristics

Geographical Density	Current Peak Load	Number of Customers	Current DG Penetration	Load Projection	DG Penetration Projection
Rural	14.6 MW	1,840	21 MW	2017: 15.6 MW 2018: 18.3 MW 2019: 18.6 MW 2020: 18.9 MW 2021: 19.2 MW	2017: 21.7 MW 2018: 22.4 MW 2019: 22.4 MW 2020: 23.0 MW 2021: 25.8 MW

7. ***Describe any relevant demonstration projects and pilots being done outside of the DRP process (for example, with EVs and the demand response reverse auction) and the coordination issues that need to be considered.***

   There are no relevant demonstration projects or pilots in this area that are being done outside of the DRP for this project.

DER PORTFOLIO and DER OWNERSHIP

8. ***If known, explain what specific DER technologies will be selected and why.***

   The exact composition of DER technologies that will be selected at this time is unknown. PG&E proposes to conduct an all-source competitive solicitation in the area to seek bids from a variety of DER providers including EE, EV, DR, DG and Energy Storage (ES) located either in front of the customer meter or behind the customer meter.

9. ***Describe what role third-party DER technology vendors will have in the project.***

   As noted in response to question 8, PG&E's intends to conduct an all-source competitive solicitation to source the DER technologies that will meet the objectives of Project D. Third-party DER technology vendors will be the focus of that solicitation.

10. ***Describe DER ownership: utility, customer, and third party with appropriate justification.***

    PG&E envisions that the all-source competitive solicitation will allow DER technology vendors to propose and price various ownership structures. PG&E will select a portfolio of DERs that represent a least-cost/best-fit outcome. . As described in the response to Question 2, one of the learning objectives of Demonstration Project D is to test whether the a DER portfolio is feasible to meet the needs for which it was procured.

BUDGET AND COST RECOVERY

11. ***Provide a breakdown of the project by activity (e.g., engineering, installation of field devices, modeling, data gathering, data analysis) and an estimated cost for each activity. Include the grand total for the project.***

    The following table summarizes the proposed work scope/activity items, schedule and preliminary budget of each work scope/activity. PG&E requests Commission authorization to recover from customers the revenue requirements necessary to fund the estimated program administration costs of the Project listed below, and to recover the additional costs of DER procurement that will be determined in a competitive solicitation for DER services for each project.

Table 4: Demonstration D Project Breakdown by Scope, Schedule and Preliminary Budget

Milestone No.	Work Scope/Activity	Category	Schedule (days are additive)	Preliminary Budget
0	CPUC Decision Approving Demos C, D and E, including cost recovery		August, 2016 (if decision is later, project viability and schedule may change)	
1	Develop Competitive Solicitation Materials and Launch/Issue Solicitation	Pre-Solicitation	90 days from CPUC Approval	$300,000
2	After Solicitation Issuance: - Respond to developer questions - Participant's Conference, if needed	Administer Solicitation		$950,000
3	Offers Received		+ 60 days	
4	Offer Evaluation - Process and Evaluate Offers - Develop Shortlist/Preferred offers		+ 90 days	
5	Negotiate and execute agreements with preferred offers		+ 180 days	
6	Prepare for CPUC Approval of DER agreements from solicitation		+ 60 days	
7	CPUC Approves DER Agreement(s) and Agreement(s) now effective		+ 90 days	
8	Final Scoping and Design Completed	Project Construction	+ 120 days	$1,000,000
9	Construction Completed		+ 330 days	
10	Acceptance Testing Completed		+ 60 days	
11	Demonstration Project Released for Operation		+ 30 days	
12	Post Demonstration Project EM&V (e.g. data gathering and analysis)	Demonstration Results	+ 365 days	$300,000
13	Post Demonstration Project Process Report		+ 60 days	
Total				**$2,100,000 + DER Procurement Cost**

12. ***What other funding and/or pilots will be leveraged by deploying the project in the proposed area?***

There are no additional pilots in this area that will be or can be leveraged for this demonstration project. However, in PG&E's current GRC filing, PG&E has requested to install a second Huron 115/12 kV distribution transformer to address projected overload conditions. Specifically, PG&E has requested funding to install this second Huron transformer to accommodate projected levels of DER penetration. In addition, the existing transformer is also projected to overload due to peak demand conditions that occur outside of peak distributed generation hours.

SCHEDULE

13. ***Provide a schedule for project design and deployment. Identify major milestones for the project and a description of the activity to be performed. Include a timetable (by year and quarter) showing when each step will be completed, including when deliverables are due.***

See the response to Question 11 for this demonstration.

DELIVERABLES AND REPORTING

14. **Identify the deliverables that are expected during the project including their due dates.**

In addition to the milestones and deliverables that are listed in the response to question 11, PG&E also proposes to provide a more refined project implementation plan, including work scope, schedule and budget. PG&E plans to provide this refined implementation with 90 days following Commission approval of the Demonstration Project.

15. ***Identify a schedule and format for reporting to the Commission interim and final results.***

In addition to the final report listed in the response to question 11, PG&E plans to provide an interim progress report to the Commission documenting the progress of this demonstration, as well as the stakeholder feedback received and actions taken to further this demonstration. The interim progress report will be submitted one year after Commission approval of the Demonstration Project.

STAKEHOLDER ENGAGEMENT AND COLLABORATION WITH THIRD-PARTIES

16. How will stakeholder participation be coordinated in the design and implementation of the project?

PG&E proposes to host quarterly meetings and reporting to stakeholders on all DRP Demonstration Projects. PG&E proposes to utilize similar reporting specifications as included in similar annual Smart Grid reports.

4. Project E

OBJECTIVES AND METHODS

1. ***Describe the project goals and the specific functions and features of DERs the project will demonstrate. Describe how the projects will demonstrate the stated goals found in the description of the demonstration project at pages 6-7 of the Attachment to the Guidance Ruling dated February 2, 2015.***

   The project goals as well as specific functions and features of DERs the project will demonstrate are summarized below:

- Project Goals: The overarching goal is to meet customer reliability needs by demonstrating management of a multiple DER microgrid using a central control system. In order to meet this, the primary goals will be: 1) serve the energy needs of Angel Island safely, reliably and cost effectively through a low carbon emissions DER portfolio, 2) further industries' understanding and experience with all aspects related to the deployment of a multiple DER microgrid including design, portfolio optimization, procurement, control/monitoring, 24/7 operation, and 3) sharing goal alignment with the California Department of Parks and Recreation (CDPR), who will be the central customer that this microgrid is serving.

- DER Functions: DERs will be dispatched and scheduled, through a central microgrid controller, in order to optimize load-generation matching, power quality, and dispatch back-up generators if needed.

- DER Features: The final selected DER portfolio will be contingent on market solicitation outcome. Two potential DER portfolios have been studied to date: 1) a portfolio that relies exclusively on renewable DER components under normal conditions which includes 370 kW of solar and wind generation, a 2 MWh Battery Energy Storage System (BESS), and two 60 kW propane generators serving only as back-up generation, 2) a portfolio of with slightly less renewable generation which includes 270 kW of solar and wind generation, a 1 MWh BESS, and two 60 kW propane generators that serve as more than just back-up generation. Environmental concerns including spill potential and air emissions favor a propane generator as back up as opposed to diesel or oil. For both portfolios, demand response opportunities exist (including shutting off electric heaters and water pumps during peak load) and energy efficiency measures would replace visitor lighting with LEDs and replace base board heaters with heat pumps.

2. ***What are the specific learning objectives and how will that inform the achievement of California's DRP Goals?***

The specific learning objectives of this demonstration include: 1) Competitive Solicitation of DERs, 2) Technical Operational Considerations of Microgrid and its applications across the electric grid.

Sourcing of a Localized DER Portfolio via a Competitive Solicitation:

PG&E will gain more knowledge and experience on how to construct least cost best fit DER portfolios based on locational factors. PG&E plans to conduct a competitive solicitation to procure a localized DER portfolio and gain more knowledge and experience on developing and implementing a solicitation for DER resources to address local distribution needs.

Technical Operational Considerations of Microgrid

Technical take-aways during scenarios of parallel operation with the grid, islanded operation, transitions back and forth between parallel and islanded operation and related effects on certain key reliability indices. [2]

3. ***What specific metrics will assess the project performance?***

The following metrics will assess project performance:

- Microgrid Service Effectiveness – Measure the effectiveness of DER dispatch with respect to meeting the 24/7 demand of the island loads. Comparative analysis will be performed evaluating projected island load profiles, DER load/generation profiles, and circuit conditions against actual island load profiles, DER load/generation profiles, and circuit conditions.
    - Example data that would be needed to develop metrics: Circuit simulation data, SCADA data, Smart meter data, DER operational data, etc.

- Microgrid Readiness & Assurance – Measuring the communication reliability between PG&E dedicated microgrid controller and the third-party owned DER equipment. Ensure that DER readiness is available when called upon during emergency services and when meeting real-time load changes. Also, measuring the reliability of protective relaying that will sense an external grid disturbance and island the microgrid.
    - Example data that would be needed to develop metrics: DER dispatch response time, Costs and schedules to complete DER siting and operation, etc.

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[2] Note that parallel operation of the microgrid with the remainder of the PG&E system will only be possible while the existing single remaining cable to the island is operational. If it fails, only isolated microgrid operation will be possible.

- Process Evaluation - A process evaluation study performed by a third party expert to be made public describing the end to end process of Project E implementation and suggesting enhancements to the future DER deployments with similar use cases. This process evaluation will also critique and provide suggestions for improvements in the process of developing least-cost/best-fit DER portfolios and the sourcing of those portfolios.

4. ***What is the project's potential for replication across the system?***

PG&E will be able to better evaluate this demonstration's potential for replication after obtaining and assessing the results of this demonstration.

PROJECT LOCATION

5. ***Identify the proposed location for the project and explain why the location was selected.***

Angel Island is an island in the San Francisco Bay offering views of the San Francisco skyline, the Marin County Headlands and Mount Tamalpais. The entire island is included within Angel Island State Park and is administered by California State Parks. The island, a California Historical Landmark, has been used for a variety of purposes, including military forts, a US Public Health Service Quarantine Station, and a US Bureau of Immigration inspection and detention facility. The Angel Island Immigration Station on the northeast corner of the island has been designated a National Historic Landmark. There are 18 permanent residents on Angel Island.

Angel Island received its bulk electric service via two 12 kilovolt (kV) submarine cables, served from the Alto 1123 circuit, until one of the cables sustained unrecoverable damage from an electrical fault. Currently, one cable is no longer in service and the other cable has been reconductored and spliced to the rest of its healthy cable section; this cable remains as the sole source of electric service to the island.

Figure 2: Geographical View of Angel Island's Electrical Configuration

The remaining submarine cable section serving Angel Island is approximately 1 mile long and crosses the Raccoon Strait in an approximately northwest-southeast direction. The two cables serving the island were installed in the 1970's, replacing cables that were installed in 1912 and 1937 and were designed with the following characteristics: 3-conductor, #2AWG Cu, 22 kV, XLPE cable with copper tape shield and galvanized steel wire armor. Due to the age of the remaining cable and the splice, it became apparent that the cable would eventually fail, so replacement of both cables became an identified project in the GRC.

Developing a microgrid on Angel Island was proposed as a potential cost effective alternative to replacing the undersea cables. Furthermore, the goals provided in the DRP Guidance Ruling dated February 2, 2015, CDPR's interest in encouraging renewable energy deployment that aligns with the Governor's clean energy and climate goals, and the opportunity to explore the potential net benefits of supplying Angel Island with a clean energy microgrid were all supportive reasons for proposing this location.

However, the prospect of operating the island as a clean microgrid raises a number of technical and operational challenges which will be the focus of this project.

6. ***Identify the relevant characteristics of the location chosen for the project (e.g., rural or urban area, current load, number of customers, current DER penetration, and projections of load and DER penetration).***

   The peak demand is about 94 kW with an average demand of about 39 kW. There is no DER penetration. Future load growth includes the addition of a Hospital Museum and switching employee driven vehicles to electric. A detailed load growth scenario is still needed. Currently, there are energy efficiency measures that can potentially reduce the annual peak demand by more than 5 kW. The following table summarizes these key attributes.

Table 5: Angel Island Characteristics

Geographical Density	Current Peak Load	Number of Customers	Current DG Penetration	*Load Projection	*DG Penetration Projection
Rural	94 kW	2	0 kW	2021: 100-128.2 kW	2021: 370 kW

*Load Projection range based on estimated range of EV growth and is likely to change. DG Projection range based on preliminary microgrid sizing study and is likely to change as a result of the competitive procurement process

7. ***Describe any relevant demonstration projects and pilots being done outside of the DRP process (for example, with EVs and the demand response reverse auction) and the coordination issues that need to be considered.***

   There are no other demonstrations at this time.

DER PORTFOLIO and DER OWNERSHIP

8. ***If known, explain what specific DER technologies will be selected and why.***

   The final selection of DER technologies is contingent on the results of the market solicitation. The selection will be based upon a number of factors including but not limited to overall cost, customer reliability, level of renewable generation, controllability and value of demonstration of microgrid technology. The following figures below are initial values from a preliminary study:

   - Wind: 200 kW: selected for the preliminary study based upon land availability, assumed cost of the generation and maintaining the historical integrity of the park.
   - PV: 70-170 kW: selected for the preliminary study to complement the assumed wind power production.
   - Battery Energy Storage: 1 MWh-2 MWh: demand shaping by charging and discharging.
   - Demand Response: Cost effectiveness of turning down non-critical loads during peak demand hours. Allows for smaller sizing of the DER system.
   - Energy Efficiency: Cost effectiveness of lowering load and allows for smaller sizing of the DER system.

- Propane generator: 60 kW x 2: back-up generation in case of battery failure or other single point of failure of the microgrid. Could also serve to improve cost effectiveness of a microgrid with smaller sized DER components (e.g. similar to the second DER microgrid studies).
- Microgrid Management Controller: to optimally serve load.

9. ***Describe what role third-party DER technology vendors will have in the project.***

   PG&E envisions the role of third-party DER technology venders will have on this project could be:

- Shape sequence of design, procurement and implementation of microgrid
- Shape procurement approach for DER solutions
- Shape the scope of procurement – e.g. by DER component or group of components, microgrid design and microgrid controller
- Microgrid controller supplier
- Provide overall control analysis and dynamic analysis of the microgrid and all of its components (Load, Wind, PV, DR, Battery and Energy Back-Up) in order to ensure the technical specs for the components are complete prior to procurement
- Overall microgrid control system and software designer
- Portfolio analysis, evaluation and selection of best mix based upon bids
- Supplier of Wind, Solar, Battery, DR and DG

10. ***Describe DER ownership: utility, customer, and third party with appropriate justification.***

    Due to the remote operating configuration for providing service to Angel Island, PG&E proposes to own, operate and maintain the Energy Storage, overall microgrid control equipment and their associated automation systems.

BUDGET AND COST RECOVERY

11. ***Provide a breakdown of the project by activity (e.g., engineering, installation of field devices, modeling, data gathering, data analysis) and an estimated cost for each activity. Include the grand total for the project.***

    The following table summarizes the proposed work scope/activity items, schedule and preliminary budget of each work scope/activity. PG&E requests Commission authorization to recover from customers the revenue requirements necessary to fund the estimated program administration costs of the Project listed below, and to recover the additional costs of DER procurement that will be determined in a competitive solicitation for DER services for each project.

Table 6: Demonstration E Project Breakdown by Scope, Schedule and Preliminary Budget

Milestone No.	Work Scope/Activity	Category	Schedule (days are additive)	Preliminary Budget
0	CPUC Decision Approving Demos C, D and E, including cost recovery		August, 2016 (if decision is later, project viability and schedule may change)	
1	Develop Competitive Solicitation Materials and Launch/Issue Solicitation	Pre-Solicitation	90 days from CPUC Approval	$300,000
2	After Solicitation Issuance: - Respond to developer questions - Participant's Conference, if needed	Administer Solicitation		$950,000
3	Offers Received		+ 60 days	
4	Offer Evaluation - Process and Evaluate Offers - Develop Shortlist/Preferred offers		+ 90 days	
5	Negotiate and execute agreements with preferred offers		+ 180 days	
6	Prepare for CPUC Approval of DER agreements from solicitation		+ 60 days	
7	CPUC Approves DER Agreement(s) and Agreement(s) now effective		+ 90 days	
8	Detailed Scoping and Design Completed for Storage and Central Control System	Project Construction	+ 180 days	$3,000,000
9	Construction Completed		+ 360 days	
10	Acceptance Testing Completed		+ 90 days	
11	Demonstration Project Released for Operation		+ 30 days	
12	Post Demonstration Project EM&V (e.g. data gathering and analysis)	Demonstration Results	+ 365 days	$400,000
13	Post Demonstration Project Process Report		+ 60 days	
Total				**$4.200,000 + DER Procurement Cost**

12. ***What other funding and/or pilots will be leveraged by deploying the project in the proposed area?***

There are no other pilots in the proposed area where funding can be leveraged.

SCHEDULE

13. ***Provide a schedule for project design and deployment. Identify major milestones for the project and a description of the activity to be performed. Include a timetable (by year and quarter) showing when each step will be completed, including when deliverables are due.***

See the response to Question 11 for this demonstration.

DELIVERABLES AND REPORTING

14. ***Identify the deliverables that are expected during the project including their due dates.***

In addition to the milestones and deliverables that are listed in the response to question 11, PG&E also proposes to provide a more refined project implementation plan, including work scope, schedule and budget. PG&E plans to provide this refined implementation with 90 days following Commission approval of the Demonstration Project.

15. ***Identify a schedule and format for reporting to the Commission interim and final results.***

In addition to the final report listed in the response to question 11, PG&E plans to provide an interim progress report to the Commission documenting the progress of this demonstration, as well as the stakeholder feedback received and actions taken to further this demonstration. The interim progress report will be submitted one year after Commission approval of the Demonstration Project.

STAKEHOLDER ENGAGEMENT AND COLLABORATION WITH THIRD-PARTIES

16. ***How will stakeholder participation be coordinated in the design and implementation of the project?***

PG&E proposes to host quarterly meetings and reporting to stakeholders on all DRP Demonstration Projects. PG&E proposes to utilize similar reporting specifications as included in similar annual Smart Grid reports.

5. Project F

1. ***Should PG&E and SCE be required to implement a "Project F" similar to one proposed by SDG&E?***

   PG&E should not be required to implement a "Project F" at this time.

   As PG&E has stated in recent IDER Joint Utility comments and workshops, the topic of new utility business models is an important one, and one that we recommend approaching comprehensively. The performance-based shared savings approach proposed by SDG&E is one of several potential mechanisms to evaluate to ensure that utility financial interests continue to be aligned with public policy objectives. However, our current focus in the DRP demonstration projects is two-fold:

   1. Validate the technical potential of non-conventional equipment and operational approaches to achieve safe and reliable grid operations
   2. Gain data on the relative costs and/or benefits and persistence of DER solutions

   If SDG&E proceeds with its Project F, we will look forward to closely tracking the learnings and implications. However, we do not see a need to duplicate this demonstration on PG&E's system.

2. ***The pilot proposal says "ratepayers and shareholders equally share all savings, if any, between the cost of the identified conventional solution and the DER solution." Would a shared-savings incentive program such as that described above achieve the objective of promoting the cost-effective deployment of DERs? If not, why not?***

   No position.

3. ***SDG&E's application doesn't specify an estimated budget. Is there need for a limit on the number of projects or the amount of dollars that a utility could propose during this pilot program? If so, what should it be?***

   No position.

4. ***Should a non-market participant stakeholder review / oversight process (such as the Procurement Review Group) be required in conjunction with this pilot?***

   No position.

5. ***How will SDG&E evaluate which locations are right for the projects?***
    a. ***What requirements will be used to determine the locations?***
    b. ***How will locations be prioritized?***

    Not applicable.

6. ***What cost does SDG&E expect to incur in performing the evaluation of which locations are appropriate for project F?***

    Not applicable.

7. ***How will SDG&E record/track the cost incurred by SDG&E to carry out the process of "identifying and incenting optimal location of DER solutions on the distribution grid"?***

    Not applicable.

8. ***How does SDG&E plan to handle circumstances when unexpected costs in DER deployment increase above the amount budgeted, especially if construction of the project has already started?***

    Not applicable.

9. ***How will SDG&E seek cost recovery in the event the "delta" dollar amount (total cost of budgeted upgrade minus total costs of the DER incentive solution) is negative (that is, the DER incentive solution cost is greater)?***

    Not applicable.

10. ***Describe how the dynamic rate(s) (for residential and small business) will be structured?***

    Not applicable.

11. ***Compare the dynamic rate to that offered under the current SDG&E's Electric Vehicle pilot.***

    Not applicable.

12. ***Will SDG&E leverage funding in developing the dynamic rate for Project F from the EV pilot?***

    Not applicable.

13. ***Why is this project limited to storage assets? Can PV or DR be incorporated?***

Not applicable.

14. ***How will this project be coordinated with Rule 21 in terms of fees, cost, and interconnection process?***

Not applicable.

6. Conclusion

PG&E appreciates the opportunity to provide these revised Demonstration Project proposals in response to the Track 2 Ruling and looks forward to participating in the upcoming workshops on this topic.

ELECTRIC PRELIMINARY STATEMENT PART XX Sheet 1
DISTRIBUTION RESOURCES PLAN DEMONSTRATION PROJECT BALANCING ACCOUNT

XX. DISTRIBUTION RESOURCES PLAN DEMONSTRATION PROJECT BALANCING ACCOUNT (DRPDPBA)

1. PURPOSE: The purpose of the Distribution Resource Plan Demonstration Project Balancing Account (DRPDPBA) is to record and track authorized revenue requirements compared to revenue requirements based on actual incurred costs associated with the Distribution Resource Plan Demonstration Projects. The DRPDPBA is a one-way balancing account. PG&E will only record actual revenue requirements up to the amount authorized by the Commission.

2. APPLICABILITY: The DRPDPBA shall apply to all customer classes, except for those schedules or contracts specifically excluded by the Commission.

3. REVISION DATE: Disposition of the balance, or over-collection, in this account will be through the Distribution Revenue Adjustment Mechanism (DRAM) as part of the PG&E's Annual Electric True-up (AET) advice filing.

4. RATES: The DRPDPBA does not have a rate component.

5. ACCOUNTING PROCEDURE: The following entries will be made to this account each month or as applicable:

   a) A credit entry equal to one-twelfth of the annual Commission-adopted revenue requirement, net of an allowance of franchise fees & uncollectibles (FF&U) that was included as a debit in the DRAM; the amount recorded in DRAM shall include FF&U;

   b) A debit entry equal to the actual incremental expenses;

   c) A debit entry equal to the capital revenue requirement (excluding FF&U) related to the incremental capital costs incurred. Capital-related revenue requirements include depreciation expense, the return on investment, federal and state income taxes, and property taxes associated with the costs of installed equipment;

   d) A debit or credit entry, as appropriate, to transfer the balance to other accounts for recovery in rates, as approved by the Commission; and

   e) An entry each month equal to the interest on the average of the balance in this subaccount at the beginning of the month and the balance in this subaccount after the above entries, at a rate equal to one-twelfth the interest rate on three month commercial paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, or its successor.

(Continued)