BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Demand-Side Resource Programs.	R.14-10-003 (Filed October 2, 2014)

OPENING COMMENTS OF THE UTILITY REFORM NETWORK ON DRAFT PROPOSAL FOR AN INCENTIVE MECHANISM FOR DISTRIBUTED ENERGY RESOURCES PROCUREMENT

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

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OPENING COMMENTS OF THE UTILITY REFORM NETWORK ON DRAFT PROPOSAL FOR AN INCENTIVE MECHANISM FOR DISTRIBUTED ENERGY RESOURCES PROCUREMENT

Pursuant to Rules 1.9 and 1.10 of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, the Utility Reform Network ("TURN") respectfully submits the following comments on the questions posed in the "Assigned Commissioner's Ruling Introducing a Draft Regulatory Incentive Proposal for Discussion and Comment" ("Assigned Commissioner's Ruling" or "ACR"), issued on April 4, 2016.

1. INTRODUCTION AND SUMMARY OF TURN'S RECOMMENDATIONS

The Assigned Commissioner's Ruling proposes to implement a pilot incentive mechanism that would reward an electric corporation with shareholder profits calculated as a direct percentage of spending on procurement contracts for distributed energy resources ("DERs"). The goal of the pilot is to provide the utility with sufficient profits that would make the utility indifferent as to whether to procure DERs owned by third parties or invest in utility-owned assets that contribute to rate base and thus utility profits. The Assigned Commissioner's Ruling outlines a six-step process that results in a utility Request for Proposals to procure DERs in order to avoid utility distribution capacity capital investments needed to address load growth on specific circuits, which are identified as "avoided costs."[1] The utility would eventually file an application for

[1] The utility capital costs that could be avoided by DERs are generally classified as "distribution capacity" costs in utility rate cases. These are investments designed to address peak demand growth on circuits. They differ from distribution investments necessary to connect new customers, replace aging infrastructure, or promote reliability. Such investments are not driven

approval of selected contracts, and would be paid a profit based on a percentage of spending, in the range of 3.5% of the contract amount.

Over the past thirty years TURN has had experience evaluating the impacts of various incentive mechanisms that have been used in California to promote investments in energy efficiency, to ensure performance of necessary functions as part of the shift to performance-based ratemaking ("PBR"), to promote efficient power plant operations, or to replace reasonableness reviews for certain procurement activities.

TURN's evaluation of the pilot and response to the questions in the Assigned Commissioner's Ruling are influenced by our experience with these other utility incentive mechanisms. TURN's analysis also considers the various policy proposals to alter the "utility business model" to promote the growth of behind-the-meter or wholesale installations on the distribution grid that either reduce demand (energy efficiency), increase local clean generation (renewable distributed generation), or provide load shifting services (demand response, battery storage). Lastly, TURN's analysis reflects our experience with utility forecasts of the relevant distribution capacity capital expenditures which are made in utility general rate cases.

In sum, TURN supports the structure of the proposed pilot. TURN agrees with the underlying analysis of utility financial incentives, and agrees that an incentive payment in the range of 3.5% of spending should in theory make the utility financially indifferent between procurement versus rate based investment. However, mere

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by load growth on existing circuits, and are likely not avoidable by DERs. The ACR also notes the possibility of counting avoided operations and maintenance expenses.

financial indifference does not mean that the utility would eschew the possibility of double dipping - earning profits from both the incentive mechanism and traditional rate base investments.

TURN is extremely concerned about the ability to achieve actual "avoided cost" benefits in the area of utility distribution capacity capital spending. The primary problem is that utility distribution capacity spending is justified based on complex load growth forecasts and analyses of potential impacts of overloading on assets such as line transformers, conductors and substation transformers. Not only is the utility information advantage huge, but also utility forecasts of specific project timelines are often wrong. Ensuring that DERs actually replace real projects will be extremely difficult. In the worst case, TURN expects that the utilities will forecast many projects that are tenuous or uncertain, and will thus obtain additional DER shareholder profits without commensurably reducing their profits from capital spending.

While TURN is skeptical that this problem can be solved by providing an "incentive" that attempts to offset a different corporate incentive, TURN does not oppose the proposed pilot. TURN recommends an improvement in the "first step" outlined in the Assigned Commissioner's Ruling. Namely, TURN recommends that the Commission contract with an outside engineering firm to review the project proposals identified by the utilities to confirm that they represent necessary and real projects that could be avoided by DERs. TURN also recommends that the Commission clarify up front that any distribution spending that should have been avoided by DERs, but that had to be done for whatever reason, would not qualify for any equity returns in the future.

2. TURN RESPONSES TO SPECIFIC QUESTIONS

1. Is the description of the source of utility shareholder value summarized above and discussed in the Appendices accurate? If not, why not?

Yes. TURN fully agrees that the utility interest in capital expenditure budgets is driven by the shareholder value created because the authorized return on equity (ROE) exceeds the utility's actual cost of equity capital. Utility authorized returns on equity in California have exceeded the utilities' actual cost of capital in at least the past fifteen to twenty years, if not longer. This fact is reflected in the substantial and growing utility capital expenditure plans, and in the utilities' focus on capital expenditure budgets in their presentations to investors.

The Commission has historically set utility ROEs in the cost of capital proceeding by 1) adopting a base range relying on utility modeling, which produces a higher range than intervenor modeling; and then 2) adopting an ROE at the high end of the utility modeled range.[2] The Commission has justified using the high end of the range based on a consideration of all market conditions and risk factors, including alleged increased risk of operations in California.

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[2] For example, D.12-12-034, p. 39 ("After considering the evidence on market conditions, trends, creditworthiness, interest rate forecasts, quantitative financial models, additional risk factors, and interest coverage presented by the parties and applying our informed judgment, we arrive at a base ROE range of 9.8%% to 10.6%. From that range we conclude that the adopted ROE should be set at the upper end of the adopted ROE range found just and reasonable.") In that case, the utility had modeled an ROE range from 9.73% to 11.71%, while all intervenors modeled the low end of the range as less than 9.20%, and going down as low as 7.60%. *Id.* at 38.

The high return on equity is reflected in utility stock prices. While PG&E's book value per share was $34.32 on December 31, 2015, a prospective shareholder would have been required to pay $53.19 to acquire a share on that day. This premium indicates PG&E's authorized rate of return is higher than its cost of capital, which in turn encourages PG&E to grow its rate base in order to maximize shareholder value.

2. ***Would an incentive program such as that described above achieve the objective of promoting the cost-effective deployment of DERs? If not, why not?***

The proposed incentive mechanism may achieve the objective; however, there is a distinct possibility that ratepayer benefits will not be as large as forecast. Due to the extreme information asymmetry and the complexity of forecasting distribution capacity projects, there is a distinct possibility that the utility may end up "double dipping," by procuring DERs in locations where there is not an actual need for utility infrastructure investment. Actual utility distribution capacity spending may not be reduced; though there is likely to be an increase in DERs on the system.

This outcome reflects the fact that competing incentive mechanisms, where one incentive is designed to negate or counter another corporate incentive, are inherently problematic. However, the problem is exacerbated for distribution capacity spending, since utility forecasts of capacity projects have often been erroneous in the past and there is tremendous information asymmetry. A tendency toward engineering conservatism, combined with the utility bias toward rate base investments, means that it will be extremely hard to guarantee "avoided costs."

a. There Are Inherent Problems With Mechanisms That Provide The Utility With Conflicting Or Competing Incentives

The Commission has adopted various incentive mechanisms over the past 30 years, including:

- Various incentive mechanisms intended to eliminate the inherent disincentive for the utility to promote energy efficiency, including the "shared savings mechanisms" starting in about 1991[3] and the present Efficiency Savings and Performance Incentive ("ESPI") mechanism,[4] which includes a hybrid of performance and shared savings incentives;
- Incentive mechanisms to promote customer service, reliability and safety to offset potential utility incentives to cut costs as part of Performance Based Ratemaking;[5]
- Shared savings incentives for natural gas procurement to replace reasonableness reviews and provide a utility incentive to minimize the cost of purchased gas;[6] and
- Various incentive mechanisms to reward the utilities for optimal power plant performance.[7]

These incentive mechanisms generally fall into two categories. Some mechanisms are designed to spur utility performance in areas that align with other corporate

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[3] See, for example, Decisions 94-10-059, 07-09-043, 09-12-045, and 12-12-032.
[4] See, D.13-09-023.
[5] For example, D.04-07-022, Sec. 13.2, p. 287-293.
[6] See, for example, D.94-03-076; D.02-06-023.
[7] For example, D.83-09-007, 12 CPUC 2d 465, 476.

financial or operational goals, such a power plant performance, customer satisfaction and reliability. In those situations, a key design feature is the use of an appropriate exogenous benchmark that can measure utility performance. However, even with supposedly “exogenous” benchmarks such as SAIDI/SAIFI or customer satisfaction, the utility can still influence underlying parameters or measurement methods to enhance utility profits.[8]

Other mechanisms are explicitly designed to offset or minimize existing corporate goals. For example, the various energy efficiency incentives provided since the early 1990’s are explicitly intended to offset the utility incentive to increase sales of kilowatt-hours in order to increase corporate growth and generation investments, even in the face of decoupling. A key design feature of incentive mechanisms that do not align with corporate goals is to ensure that ratepayers actually get the “benefits” due to “avoided costs.” For energy efficiency, those benefits derive primarily from avoided generation, which in practice is a reduction in the operation of existing power plants. The traditional utility disincentive toward energy efficiency may be somewhat reduced due to the more limited utility role in constructing and operating power plants.

The proposed pilot is similarly intended to offset the utility goal to increase distribution capital investments so as to increase rate base and profits.[9] The proposed pilot would provide the utilities with profits intended to approximately equal (or be

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[8] A perhaps extreme example of such manipulation involved the fraud committed to enhance customer satisfaction scores for SCE, leading to sanctions worth approximately $200 million. See, D.08-09-038.

[9] Assigned Commissioner’s Ruling, p. 3.

somewhat less than) than the profits the utilities would otherwise earn on distribution capacity capital investments. This may be a challenging goal given the increased importance of distribution capital additions for utility rate base growth.[10]

There are at least two key theoretical problems with an incentive mechanism that attempts to offset other corporate goals. The first is the potential for the utility to maximize profits from both the incentive mechanism and the traditional investment, due to the serious information asymmetry concerning the nature of "avoided costs." In essence, the Commission creates a mechanism where the utility can earn profits by pushing the accelerator (utility distribution investment) and by putting on the brake (DER procurement from third parties). While one can eventually get to the intended destination, the trip creates more wear and tear and costs more. Reducing the potential for utilities to double-dip is TURN's primary focus in our recommendations provided in response to Question No. 6 below.

The second theoretical problem is that the underlying assumption that the utility is indifferent between different profit streams is not wholly correct. While TURN agrees that maximizing net earnings is the key corporate goal, a large utility is also interested in revenue growth and corporate size, both for financial and "soft" reasons. Thus, the utility is not wholly indifferent to earning profits from capital investments that generate

[10] The only potential saving grace is that distribution capacity spending has become a lower percentage of overall distribution capital spending, since the main drivers of distribution spending presently are infrastructure replacement, reliability and automation. For example, in PG&E's current rate case (A.15-09-001), distribution capacity spending forecast of 2017 comprises $211 million out of a total distribution capital forecast of $1,819 million. See, PG&E-04, ch. 13, Table 1A-5 and Figure 13-2.

jobs and revenues, versus from third-party procurement that may minimize labor force and revenues.

b. The Pilot Does Not Sufficiently Address the Difficulties of Ensuring Actual "Avoided Costs" Based on Real Distribution Capacity Projects Proposed for Deferral

There are two key steps necessary to ensure procurement of DERs results in avoided utility capital investments: 1) how to ensure that capital projects proposed by the utilities are "real" projects that would otherwise be constructed; and 2) how to ensure that the utility does not end up constructing the project in any case. The second part is amenable to specific ratemaking solutions, as described in response to Question No. 6. In this section TURN details the inherent difficulty in ensuring that proposed capital projects are real; and in response to Question No. 6 TURN provides some process recommendations to address this issue.

That key problem is that the utility may forecast "opportunities for the cost-effective deployment of DERs on their systems" that do not in reality displace any utility investments, either by design or by accident, and are thus not really "cost-effective." The utility ends up earning profits from both the distribution investment and the DER procurement, without avoiding any costs.

This problem is partly inherent from the planning process for distribution capacity investments. Distribution capacity investments include work such as replacing substation transformers, replacing underground and line transformers, reconductoring, and replacing protective equipment.[11] The work is driven by three to five-year load forecasts at the circuit or substation level that are reviewed annually. Those forecasts are based on both historical load data, but also on subjective data concerning future load growth based on utility conversations with local government officials and developers.

Utility load forecasts at the local level are inherently uncertain, so that projects proposed in a particular year may be deferred if the underlying assumptions change. For example, if a planned commercial development is derailed for any number of business reasons, the utility may choose to defer the capacity upgrade anyway.

Utility rate case applications provide numerous examples of distribution capacity project deferments, whether due to forecast error, permitting delays or some other reason.[12] For example, the Alberhill substation project had been forecast for completion by 6/1/2014 in SCE's 2012 rate case, but was forecast for completion by June 2017 in the 2015 rate case.[13] The Colonia and Lakeview substation projects were both forecast for completion by June 2013 at a cost of about $19.2 million, but were

[11] For example, Attachment 1 includes the entirety of PG&E's electric distribution capacity testimony from its current test year 2017 rate case (PG&E-04, chapter 13), and describes both the planning process and the forecast investments. Attachment 2 includes a similar excerpt from SCE's 2014 test year rate case.

[12] For example, D.12-11-051, Sec. 5.4.2, p. 139 (SCE's forecast of 27 projects "including four previously approved by the Commission but deferred due to permit delays"); Sec. 5.4.3, p. 141 ("Expenditures for several projects were previously approved by the Commission in the 2009 GRC, but deferred due to permitting delays.").

[13] Compare project 18 in Table II-5 in Appendix A (2012 GRC) with project 11 in Table I-11 in Appendix B (2015 GRC). TURN does not suggest that SCE did anything improper; rather, these examples illustrate that major project timeline forecasts are subject to significant error.

included in the next rate case with forecast completion dates of June 2015 and June 2016.[14]

In its current Test Year (TY) 2017 rate case PG&E includes about 19 distribution capacity projects that had been included in its prior Test Year 2014 rate case forecast. PG&E explained that some of these projects were deferred due to reprioritization across the Electric Distribution line of business, at least in part due to "the increase in agricultural pumping requirements caused by the drought."[15] Some projects from TY 2011 were also included in the TY 2017 rate case for multiple reasons, including project deferral due to "reprioritization" – PG&E's explanation for these projects are attached to these comments to provide concrete examples of the issue at hand.[16]

These examples identify projects that were requested in multiple rate cases. TURN is not aware of any party that actually checked to see whether all the other projects that were forecast in a rate case were actually completed, or whether some were completely canceled due to lack of need or changed demand forecasts.

TURN would not be surprised if the potential to earn profits on deferred capital expenditures might result in a general utility philosophy to "forecast liberally." Utility forecasts are based on very local demand forecasts, as well as on engineering

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[14] Compare projects 53 and 54 in Table II-8 in Appendix A (SCE testimony from 2012 GRC) with projects 21 and 25 in Table I-14 in Appendix B (SCE Testimony from 2015 GRC). TURN does not mean to pick on SCE; rather, the tables provided by SCE in its rate case testimony are extremely useful in identifying forecast work. PG&E does not provide similar data in its testimony and work papers, and thus is much less transparent about the basis for its distribution capacity forecasts.

[15] Data request TURN_045_Q04 from the GRC, Appendix C to these comments.

[16] Data request TURN_068_Q01_Atch02 from the GRC, Appendix D to these comments.

assessments of the impact of demand growth on specific distribution equipment. An inherent engineering bias towards conservative forecasts would not be surprising. In addition, utility planners may make more conservative subjective judgements concerning peak demand growth and the impact of exceeding the thermal rating of a transformer by some percentage for a few hours a year, if they knew that there was a likelihood that asset investments would be replaced by third party DER installations. The information advantage by the utility in this area is enormous, and neither TURN nor ORA have the resources to evaluate utility forecasts closely in this area.

TURN is concerned that an incentive program that depends on utility forecasts of distribution capacity projects may well result in the utility obtaining DER incentives for capital projects that would never have been built anyway, whether due to forecast errors or overly conservative forecasts by utility distribution planners. The Assigned Commissioner's Ruling suggests that the utilities will "identify" the cost-effective deployment opportunities, which would be then reviewed by a Distribution Planning Review Group. TURN is extremely concerned about the efficacy of this process, and provides additional proposals in response to Question No. 6 below.

3. ***What alternative approaches should the Commission consider at this time?***

TURN does not oppose piloting a mechanism that provides utility an incentive calculated as a percentage of spending on a procurement contract.

However, TURN is not convinced that such a mechanism will provide the most effective means of promoting DER installation at the lowest cost to ratepayers. TURN encourages the Commission to keep in mind less expensive alternatives when evaluating the results of any adopted pilot.

The ACR notes that the Commission could "just *direct* the utilities to choose DERs whenever they are less costly than traditional distribution investments";[17] however, the ACR dismisses this approach based on practical considerations, concluding that the Commission is "ill-equipped" to evaluate "when and where such DER deployment opportunities may exist," and that "command-and-control regulation faces major challenges in this context."[18] Indeed, in theory the utilities should already be procuring DERs instead of utility investments, as ordered in D.03-06-028,[19] but TURN is not aware of any such procurement happening.

However, TURN suggests that there may be alternative models that promote DER procurement and/or DER installation without requiring intensive Commission review of utility distribution plans and operations, and without paying utilities profits that are designed to offset other "profits." TURN does not suggest any particular mechanism at this point in time; nevertheless, TURN will explore this issue as we evaluate the utility response to the proposed pilot.

4. ***Is the proposed incentive, in the range of 3.5% grossed up for taxes, approximately correct?***

TURN agrees that the incentive based on "r minus k" grossed up for taxes would be in the range of 3.5%. A more accurate figure could be determined by examining the

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[17] ACR, p. 7 (emphasis in original).
[18] ACR, p. 7.
[19] D.03-06-028, Ordering Paragraphs 1-5, p. 81.

modeling results submitted for the Commission's consideration in cost of capital proceedings. The maximum size of "k" would be the delta between the ranges of modeling results presented in that case.

In the last cost of capital proceeding, Application 12-04-015, the result was an authorized ROE (10.45%for SCE) that was 2.25% above the lowest weighted average modeled result of 8.20%, and 2.85% above the lowest modeled result of 7.60%.[20]

5. ***Are there other disincentives to the deployment of DERs that this proposal does not address that should be considered at the same time? If so, please explain.***

6. ***Is the suggested process for identifying and approving DER projects that would generate an incentive reasonable and appropriate? How could the process be improved?***

While the process outlined in the April 4, 2016 Ruling seems reasonable in terms of balancing transparency and confidentiality issues, TURN's primary concern is how parties and the Commission can ensure that utility projects proposed for deferral are actually needed and necessary on the time frame forecast by the utilities. In other words, the question is how can we be sure that what the utilities claim would be the "avoided costs" due to DER procurement are really costs that the utility would otherwise incur. Absent such certainty, there is a significant probability that actual avoided costs will always be less than forecast avoided costs due to the inclusion of projects that would be delayed or terminated for multiple other reasons, aside from the procurement of DERs.

[20] D.12-12-034, p. 38. These numbers present the results for SCE, but the results are similar for the other three IOUs.

Under the process outlined in the Ruling, the "Distribution Planning Review Group" (DPRG) would review utility proposals to ensure the projects to be deferred/avoided by DERs are "real" and necessary in the year identified by the IOU. At the same time, the Ruling admits that even the "Commission is ill-equipped"[21] to identify DER deployment opportunities to avoid or defer distribution capital projects. Regrettably, TURN believes the DPRG on its own would be similarly ill-equipped to vet utility assumptions and analyses that determine these projects. TURN's conclusion is based on our participation in multiple rate cases where TURN and the ORA have attempted to evaluate some of the utility distribution capacity forecast costs.

This issue is fundamental to ensuring net benefits from DER deployment. The Ruling states that ratepayer savings from deployment of DERs will be realized "as long as the amount paid to the DER provider, plus the cost of the utility incentive, is less than the cost of the avoided or deferred utility capital investment."[22] However, this is only true if the project identified by the utility must *actually* be deferred/avoided in the year claimed. This will be very difficult if not impossible for parties like TURN, ORA, and Energy Division to ascertain in the context of the DPRG.

To help mitigate this problem, TURN recommends first that Energy Division be authorized to contract with an outside engineering firm for the following purposes:

1) Understand and vet utility distribution planning processes that led to the selection of particular projects;

2) Determine whether utility distribution peak demand forecasts accurately reflect

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[21] Assigned Commissioner's Ruling, p. 7.
[22] Assigned Commissioner's Ruling, p. 8.

important assumptions like the effect of energy efficiency and solar PV on future demand and why load is expected to grow in coming years;

3) Explain to the DPRG critical utility assumptions that effect whether or not a particular project needs to be deferred/avoided in a particular year;

4) Provide recommendations on which projects, if any, are most likely "necessary" and ought to be selected for deferral/avoidance by DERs.

Implicit in number four above is TURN's belief that the DPRG and external engineering firm be presented with a number of projects from which to select for deferral/avoidance by DER deployment. While the role of the external engineering firm is somewhat analogous to the role of the Independent Evaluator presently employed by the utilities to provide input on utility procurement issues, TURN emphasizes that in this case the firm should be directly retained by the Commission, not by the utility.

Second, TURN recommends a ratemaking process necessary to hold the utilities accountable *ex-post* after a particular project has supposedly been deferred or avoided. The Commission must ensure that utilities do not profit from installing assets on circuits where projects were supposedly deferred with DER procurement. Thus, if the utility's forecast is inaccurate and it actually proceeds with the conventional "avoided" capacity project before the deferral period expires, the utility should earn no equity return on that capital spending, and only earn its cost of debt. For example, if DER deployment is expected to defer a particular substation transformer upgrade for 5 years, but the utility must nevertheless replace the transformer after three years, the project would collect only the cost of debt. This "disincentive" mechanism would help minimize costs of upgrades within the deferral period and aid in selection of projects that would actually realize the net benefits of DER deployment calculated before deployment.

The utility may argue that lack of performance by contracted DER may require utility investments that were supposed to be deferred. Any such lack of performance should be handled by contractual performance guarantees that would make ratepayers whole if a DER contract does not perform sufficiently to defer the investment. Such guarantees will require careful description of the "products and services" that would be provided by the DER, as contemplated in steps two and three of the outlined process.

The Commission must also ensure that any "project" is broadly defined to prevent manipulation. For example, the utility cannot claim that a project involves replacing a substation transformer, but then go ahead and replace line transformers or conductors due to the same load growth issue. This is an important issue since the utility can mitigate a load growth problem with several different alternatives. It will be important to ensure that DER procurement avoids all future capacity investments driven by the same underlying load growth.

7. ***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?***

The ACR explains that in order to ensure that there are net benefits to ratepayers, the utility should use the Locational Net Benefits Analysis to ensure that DERs are deployed in "locations where the benefits exceed the cost." TURN strongly supports this criterion, though it is not *per se* a limit on the number of projects or dollars for spending.

Furthermore, a "pilot" should be somewhat limited in scope, since the ultimate benefit, usefulness and efficacy of the procurement mechanism has yet to be tested. From the ratepayer perspective, a key issue will be to ensure avoided costs. From the utility perspective, a key question will be whether the DER will function with sufficient certainty and performance to allow for deferment of standard investments for the necessary amount of time. A pilot should ideally collect enough information to test the impact of various design parameters.

TURN has not analyzed how best to determine a limit. One option would be simply to target a percentage of the utility's forecast distribution capacity spending. For example, PG&E forecasts about $211 million in 2017 capacity spending, so a potential limit could be 10% of this amount on an annual basis. However, it may make more operational sense to limit procurement to a certain number of feeders, and select feeders based on the operational ability of DER to avoid or defer specific types of investments. TURN looks forward to reviewing other parties' proposals for any limitation to the initial pilot deployment.

8. ***Would participation in a DER solicitation by a utility affiliate require any changes to the Affiliate Transaction Rules, or any changes to the process for review and approval of proposed DER solutions?***

   No comment at this time.

9. ***What would be the appropriate role of the IOUs themselves in the deployment of cost-effective DERs? Should direct IOU participation in DER deployment be encouraged, foreclosed, or allowed with certain caveats? Please fully explain your answer.***

No comment at this time.

Date: May 9, 2016

Respectfully submitted,

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APPENDIX A

Excerpt from SCE Testimony in A.10-11-015 (TY 2012 GRC)

Application No.:	
Exhibit No.:	SCE-03, Vol. 03 Part 01 & 02, Ch. I-II
Witnesses:	R. Woods

(U 338-E)

2012 General Rate Case

Transmission And Distribution Business Unit (TDBU)
Volume 3
Part 1 – Electric System Planning
Part 2 – Load Growth Programs
Chapters I-II

Before the

Public Utilities Commission of the State of California

Rosemead, California
November 2010

Table II-5
A-Bank Plan Capital Expenditure Summary ($000)

Line No.	Project No.	Project Name	Op Date	Prior	2010	2011	2012	2013	2014	Total Through 2014
1	05065	Del Amo 220/66 kV Substation	12/30/2010	4,087	8,867	-	-	-	-	12,954
2	05384	Rio Hondo 220/66 kV Substation	6/1/2010	1,633	8,707	1,000	-	-	-	11,340
3	06807	Valley 500/115 kV Substation	12/31/2010	542	4,600	3,158	-	-	-	8,300
4	05075	El Casco 220/115 kV Substation	4/1/2011	45,703	36,018	14,752	-	-	-	96,473
5	05077	Santa Clara 220/66 kV Substation	6/1/2011	743	7,580	9,477	-	-	-	17,800
6	05309	Rector 220/66 kV Substation	6/1/2011	135	2,099	7,082	-	-	-	9,316
7	06219	Goleta 220/66 kV Substation	6/1/2011	-	1,000	2,000	-	-	-	3,000
8	06221	Ellis 220/66 kV Substation	6/1/2011	121	3,652	10,995	-	-	-	14,768
9	06668	Valley 500/115 kV Substation	3/1/2011	750	10,800	5,650	-	-	-	17,200
10	06227	Santiago 220/66 kV Substation	6/1/2012	177	255	898	8,382	-	-	9,712
11	06675	Moorpark 220/66 kV Substation	2/1/2012	-	-	526	2,293	-	-	2,819
12	06824	La Fresa 220/66 kV Substation	6/1/2012	-	100	2,208	13,906	-	-	16,214
13	06107	Saugus 220/66 kV Substation	6/1/2013	-	160	3,543	20,629	13,924	-	38,256
14	06284	La Cienega 220/66 kV Substation	6/1/2013	128	500	1,172	16,658	7,423	-	25,881
15	06825	Hinson 220/66 kV Substation	6/1/2013	-	-	713	3,669	1,956	-	6,338
16	06845	Gould 220/66 kV Substation	11/1/2013	49	-	20	210	1,396	-	1,675
17	05081	Villa Park 220/66 kV Substation	6/1/2014	-	-	-	24	1,319	1,070	2,413
18	06092	Alberhill 500/115 kV Substation	6/1/2014	48,240	4,480	68,853	96,185	66,814	58,001	342,573
19	06317	Etiwanda 220/66 kV Substation	6/1/2014	-	-	-	5,099	6,903	13,767	25,769
20	06670	Valley 500/115 kV Substation	2/1/2014	-	-	-	200	10,700	3,500	14,400
21	06671	Johanna 220/66 kV Substation	6/1/2014	-	-	-	-	8,245	3,466	11,711
		Subtotal for 21 Projects > $1M		**102,308**	**88,818**	**132,047**	**167,255**	**118,680**	**79,804**	**688,912**
		Subtotal for 5 Projects < $1M		**83**	**242**	**40**	**1,580**	**25**	**0**	**1,970**
		Total A-Bank Plan		**102,391**	**89,060**	**132,087**	**168,835**	**118,705**	**79,804**	**690,882**

Twenty-one projects have been identified with project costs equal to or greater than $1 million. A description and justification for each of these projects is provided below. The total cost for these twenty-one projects is $688.912 million, or approximately 99.7% of the overall A-Bank Plan cost. The remaining 0.3% of the A-Bank Plan cost, or $1.970 million, is for five projects with costs less than $1 million each. The total cost for the projects in the A-Bank Plan is $690.882 million.

(1) Del Amo 220/66 kV Substation (Project #05065)

Del Amo 220/66 kV Substation is located in the city of Cerritos and serves the areas of Artesia, Bellflower, Cerritos, Cypress, La Mirada, Lakewood, Long Beach, Norwalk, and Santa Fe Springs. By 2011, Del Amo 220/66 kV Substation is projected to exceed its capacity limit due to continuing load growth in the area. The project scope is to energize an existing spare 280 MVA transformer bank and install a new spare 280 MVA transformer bank at Del Amo 220/66 kV Substation, thereby increasing total transformer capacity from 560 MVA to 840 MVA at the station. Without the project, the loading at Del Amo 220/66 kV Substation is projected to reach 101.0% of the substation's

Table II-8
Distribution Substation Plan Capital Expenditure Summary ($000)

Line No.	Project No.	Project Name	Op Date	Prior	2010	2011	2012	2013	2014	Total Through 2014
1	04414	Trophy 66/12 kV Substation	6/1/2010	877	1,928	-	-	-	-	2,805
2	04427	Estrella 66/12 kV Substation	6/1/2010	225	2,615	-	-	-	-	2,840
3	04734	Mira Loma 66/12 kV Substation	6/1/2010	1,305	1,300	-	-	-	-	2,605
4	04771	Tenaja 115/12 kV Substation	6/1/2010	3,862	9,563	-	-	-	-	13,425
5	05176	Kimball 66/12 kV Substation	8/31/2010	7,160	7,399	-	-	-	-	14,559
6	05286	Coso 115/12 kV Substation	8/1/2010	516	4,562	-	-	-	-	5,078
7	05293	Narrows 66/12 kV Substation	6/1/2010	767	1,733	-	-	-	-	2,500
8	05372	Devers 115/12 kV Substation	6/1/2010	3,324	1,606	-	-	-	-	4,930
9	05401	Barre 66/12 kV Substation	6/1/2010	1,056	3,500	-	-	-	-	4,556
10	06008	Elizabeth Lake 66/16 kV Substation	6/1/2010	793	3,700	-	-	-	-	4,493
11	06013	Palmdale 66/12 kV Substation	6/1/2010	1,272	245	-	-	-	-	1,517
12	06022	Aqueduct 115/12 kV Substation	6/1/2010	1,225	2,000	-	-	-	-	3,225
13	06068	Irvine 66/12 kV Substation	6/1/2010	2,451	3,483	-	-	-	-	5,934
14	06108	Etiwanda 66/12 kV Substation	6/1/2010	1,137	1,800	-	-	-	-	2,937
15	06321	Cabrillo 66/12 kV Substation	6/1/2010	643	830	-	-	-	-	1,473
16	06562	Bradbury 66/16 kV Substation	6/1/2010	744	1,497	-	-	-	-	2,241
17	06746	MacArthur 66/12 kV Substation	6/1/2010	820	1,488	-	-	-	-	2,308
18	05061	Sun City 115/12 kV Substation	6/1/2011	-	169	3,361	-	-	-	3,530
19	05289	Fogarty 115/12 kV Substation	6/1/2011	4,863	4,767	1,820	-	-	-	11,450
20	05291	Corona 66/33 kV Substation	6/1/2011	21	1,280	3,000	-	-	-	4,301
21	05353	Triton 115/12 kV Substation	6/1/2011	2,356	7,289	7,581	-	-	-	17,226
22	05479	Oasis 66/12 kV Substation	5/1/2011	2,353	2,000	5,077	-	-	-	9,430
23	06216	Oceanview 66/12 kV Substation	6/1/2011	-	785	1,915	-	-	-	2,700
24	06226	Niguel 66/12 kV Substation	6/1/2011	-	757	1,553	-	-	-	2,310
25	06229	Lafayette 66/12 kV Substation	6/1/2011	-	809	3,191	-	-	-	4,000
26	06287	Bunker 115/12 kV Substation	6/1/2011	-	2,153	5,972	-	-	-	8,125
27	06362	Bliss 66/12 kV Substation	6/1/2011	73	2,000	7,457	-	-	-	9,530
28	06568	Little Rock 66/12 kV Substation	6/1/2011	-	1,651	4,937	-	-	-	6,588
29	06612	Tipton 66/12 kV Substation	6/1/2011	-	781	4,229	-	-	-	5,010
30	06809	Cudahy 66/16 kV Substation	6/1/2011	-	173	2,927	-	-	-	3,100
31	06815	Morro 66/12 kV Substation	6/1/2011	27	351	1,972	-	-	-	2,350
32	06933	Downs 33/12 kV Substation	6/1/2011	-	595	1,380	-	-	-	1,975
33	06934	Bassett 66/12 kV Substation	6/1/2011	-	144	1,806	-	-	-	1,950
34	04422	Las Lomas 66/12 kV Substation	6/1/2012	1,154	974	11,436	8,820	103	-	22,487
35	04445	Glen Avon 66/12 kV Substation	6/1/2012	-	35	1,162	3,153	-	-	4,350
36	04605	Narod 66/12 kV Substation	6/1/2012	-	24	766	2,260	-	-	3,050
37	05023	El Sobrante 33/12 kV Substation	6/1/2012	-	57	2,026	5,109	-	-	7,192
38	05194	Presidential 66/16 kV Substation	6/1/2012	2,259	3,755	8,256	14,715	-	-	28,985
39	05396	Mascot 66/12 kV Substation	6/1/2012	1,021	1,672	9,989	11,927	-	-	24,609
40	06300	Chestnut 66/12 kV Substation	6/1/2012	-	115	800	2,895	-	-	3,810
41	06577	Devers 115/12 kV Substation	6/1/2012	-	20	480	3,500	-	-	4,000
42	06586	Laurel 66/12 kV Substation	6/1/2012	-	-	784	4,439	-	-	5,223
43	06827	Ely 66/12 kV Substation	6/1/2012	-	-	417	2,526	-	-	2,943
44	06829	Vera 66/12 kV Substation	6/1/2012	-	10	600	3,080	-	-	3,690
45	06831	Jefferson 66/12 kV Substation	6/1/2012	-	-	500	2,350	-	-	2,850
46	06858	Telegraph 66/12 kV Substation	6/1/2012	-	-	545	5,937	-	-	6,482
47	06948	Carodean 115/12 kV Substation	6/1/2012	-	-	222	1989	-	-	2,211
48	04458	Pepper 115/12 kV Substation	6/1/2013	-	-	36	2,262	2,252	-	4,550
49	04469	Wimbledon 66/12 kV Substation	6/1/2013	-	20	22	1,372	1,387	-	2,801
50	04581	Mayberry 115/12 kV Substation	6/1/2013	457	391	515	610	968	-	2,941
51	05027	Saticoy 66/16 kV Substation	5/1/2013	-	-	70	2,000	1,180	-	3,250
52	05034	Douglas Park 66/12 kV Substation	6/1/2013	17	98	140	10,998	7,334	-	18,587
53	05403	Colonia 66/16 kV Substation	6/1/2013	-	-	16	1,021	1,017	-	2,054
54	05411	Lakeview 115/12 kV Substation	6/1/2013	-	550	3,200	3,673	9,742	-	17,165
55	05432	Roadway 115/12 kV Substation	6/1/2013	-	-	69	4,279	4,261	-	8,609
56	06220	Fillmore 66/16 kV Substation	6/1/2013	-	-	20	1,227	1,222	-	2,469
57	06587	Nelson 115/12 kV Substation	6/1/2013	-	-	20	1,263	1,257	-	2,540
58	06605	La Habra 66/12 kV Substation	6/1/2013	-	-		310	3,490	-	3,800
59	06619	Banducci 66/12 kV Substation	6/1/2013	-	572	2,019	5,000	10,817	-	18,408
60	06828	Lennox 66/16 kV Substation	6/1/2013	-	-	-	264	2,023	-	2,287
61	06854	Thornhill 115/12 kV Substation	6/1/2013	-	-	-	1,603	2,239	-	3,842
62	04624	Brea 66/12 kV Substation	6/1/2014	-	-	-	32	1,988	1,980	4,000
63	05186	Moreno 115/12 kV Substation	6/1/2014	-	-	-	29	1,791	1,783	3,603
64	05315	Tulare 66/4 kV Substation	6/1/2014	-	-	-		161	1,032	1,193
65	05389	Levy 66/16 kV Substation	6/1/2014	-	-	-	49	3,022	3,009	6,080
66	05397	Falcon Ridge 66/12 kV Substation	6/1/2014	212	515	1,000	2,155	11,775	9,014	24,671
67	06076	Genamic 66/12 kV Substation	6/1/2014	-	-	-	109	5,851	7,017	12,977
68	06371	Ojai 66/16 kV Substation	6/1/2014	-	-	-	14	845	841	1,700
69	06575	Circle City 66/12 kV Substation	6/1/2014	117	150	825	1,925	2,700	7,604	13,321
70	06598	Shawnee 66/12 kV Substation	6/1/2014	-	-	-	-	1,100	1,750	2,850
71	06691	Downs 115/12 kV Substation	6/1/2014	85	500	1,000	2,320	4,327	8,196	16,428
72	06847	Guardian 66/12 kV Substation	6/1/2014	-	400	1,575	1,611	9,110	9,583	22,279
73	06857	Walteria 66/16 kV Substation	6/1/2014	-	-	-	-	257	2,282	2,539
74	06958	Pebbly Beach Generating Station	7/31/2014	-	75	2,000	9,000	800	0	11,875
75	04837	Substation Automation Upgrades	2010-2014	-	1,093	1,126	1,159	1,194	1,230	5,802
		Subtotal for 75 Projects > $1M		**43,192**	**85,979**	**109,814**	**126,985**	**94,213**	**55,321**	**515,504**
		Subtotal for 101 Projects < $1M		**2,527**	**8,531**	**7,453**	**5,436**	**5,532**	**3,238**	**32,717**
		Total Distribution Substation Plan		**45,719**	**94,510**	**117,267**	**132,421**	**99,745**	**58,559**	**548,221**

APPENDIX B

Excerpt from SCE Testimony in A.13-11-003 (TY 2015 GRC)

Application No.:	
Exhibit No.:	SCE-03, Vol. 03
Witnesses:	R. Woods

SOUTHERN CALIFORNIA EDISON®

An *EDISON INTERNATIONAL®* Company

(U 338-E)

2015 General Rate Case

Transmission and Distribution (T&D) Volume 3 – System Planning Capital Projects

Before the

Public Utilities Commission of the State of California

Rosemead, California
November 2013

Table I-11
A-Bank Plan Capital Expenditure Summary
(Total Company Nominal $000)

Line No.	Project #	Project Name	Operating Date	Prior	2013	2014	2015	2016	2017	Total
1	05075	El Casco 220/115 kV Substation	Jun 2013	115,416	1,977	-	-	-	-	117,392
2	05360	Devers-Mirage 115kV System Split	Jun 2013	30,800	160	-	-	-	-	30,960
3	06807	Valley 'C' 500/115 kV Substation	Jun 2013	4,929	100	-	-	-	-	5,029
4	06221	Ellis 'C' 220/66 kV Substation	Jul 2013	23,043	812	-	-	-	-	23,854
5	06227	Santiago 220/66 kV Substation	Dec 2013	185	8,886	-	-	-	-	9,071
6	06284	La Cienega 220/66 kV Substation	Jun 2014	13,768	1,721	1,387	-	-	-	16,877
7	06824	La Fresa 220/66 kV Substation	Dec 2014	17,820	14,413	15,148	147	2	-	47,530
8	06263	Vestal 220/66 kV Substation	Jun 2015	2,597	2,998	6,621	6,378	-	-	18,593
9	06670	Valley 'AB' 500/115 kV Substation	Mar 2016	193	4,026	14,209	8,335	4,302	-	31,065
10	05383	Chino 220/66 kV Substation-Phase 1	Jun 2016	575	50	6,007	14,724	23,632	-	44,988
11	06092	Alberhill 500/115 kV Substation	Jun 2017	30,064	14,886	85,668	95,635	107,141	52,809	386,203
12	06107	Saugus 'C' 220/66 kV Substation	Jun 2017	3,021	7,957	37,184	15,905	2,912	1,716	68,695
13		**Total A-Bank Plan**		242,410	57,985	166,224	141,124	137,989	54,525	800,258

Twelve A-Bank projects have been identified with project costs equal to or greater than $1 million. A description and justification for each of these projects is provided below. The total cost for these twelve projects is $800.3 million of which $396.3 million is CPUC-jurisdictional cost forecast from 2013 to 2017.

(1) El Casco 220/115 kV Substation (Project #05075)

El Casco 220/115 kV Substation[57] is a new planned substation to be located in the city of Calimesa. The purpose of the project is to build electrical facilities necessary to serve forecast demand in north Riverside County and to maintain safe and reliable service to customers in this area. The project scope is to construct a new substation consisting of two 280 MVA, 220/115 kV transformer banks, two 28 MVA, 115/12 kV transformer banks, and three new 12 kV distribution circuits. The project scope also includes rebuilding and reconstructing approximately 15 miles of existing 115 kV subtransmission lines, rebuilding the existing 115 kV switchracks at both Banning 115/33 kV Substation and Zanja 115/33 kV Substation, and installing telecommunications equipment at both the El Casco Substation and SCE's existing Mill Creek Communications site. The operating date is June 2013 with a total project cost of $117.392 million.[58] This project was included in SCE's 2012

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[57] *See* Application A.07-02-022 (Proponent's Environmental Assessment–El Casco System Project) for a detailed discussion of the purpose and need for this project.

[58] Refer to workpaper entitled "El Casco 220/115 kV Substation (Project #05075)."

Table I-14
Distribution Substation Plan Capital Expenditure Summary
(100% CPUC-Jurisdictional Nominal $000)

Line No.	Project #	Project Name	Operating Date	Prior	2013	2014	2015	2016	2017	Total
1	04422	Las Lomas 66/12 kV Substation	Nov 2012	44,817	3,000	-	-	-	-	47,817
2	05396	Mascot 66/12 kV Substation	Dec 2012	27,104	325	-	-	-	-	27,429
3	05353	Triton 115/12 kV Substation	Apr 2013	29,146	2,470	-	-	-	-	31,616
4	04458	Pepper 115/12 kV Substation	Jun 2013	3,666	5,519	-	-	-	-	9,185
5	05023	El Sobrante 33/12 kV Substation	Jun 2013	5,163	3,363	-	-	-	-	8,526
6	05432	Roadway 115/12 kV Substation	Jun 2013	4,497	7,304	-	-	-	-	11,800
7	06093	Bloomington 66/12 kV Substation	Jun 2013	684	2,958	-	-	-	-	3,642
8	06220	Fillmore 66/16 kV Substation	Jun 2013	3,006	1,085	-	-	-	-	4,091
9	06577	Devers 115/12 kV Substation	Jun 2013	8,485	8,249	-	-	-	-	16,734
10	06605	La Habra Project 66/12 kV Substation	Jun 2013	3,740	10,938	-	-	-	-	14,677
11	06870	Estrella 66/12 kV Substation	Jun 2013	1,456	3,317	-	-	-	-	4,773
12	06948	Carodean 115/12 kV Substation	Jun 2013	2,904	3,034	-	-	-	-	5,938
13	07160	Delano 66/12kV Substation	Jun 2013	6,008	5,599	-	-	-	-	11,607
14	04445	Glen Avon 66/12 kV Substation	Jun 2013	2,103	499	-	-	-	-	2,603
15	06292	Lampson 66/12 kV Substation	Jun 2014	0	1,557	2,390	-	-	-	3,947
16	06691	Downs 115/12 kV Substation	Jun 2014	2,163	10,777	19,315	-	-	-	32,256
17	06958	Pebbly Beach 12/2.4 kV Substation	Jun 2014	783	614	315	-	-	-	1,712
18	07216	Del Amo Jr 66/12 kV Substation	Jun 2014	661	1,491	24,626	-	-	-	26,778
19	07263	La Palma 66/12 kV Substation	Jun 2014	48	7,842	5,922	-	-	-	13,812
20	07391	Lark Ellen 66/12 kV Substation	Jun 2014	175	2,448	1,763	-	-	-	4,385
21	05403	Colonia 66/16 kV Substation	Jun 2015	129	320	2,878	3,686	-	-	7,014
22	06301	Canyon 66/12 kV Substation	Jun 2015	220	2,259	1,349	809	-	-	4,637
23	07307	San Dimas 66/12 kV Substation	Jun 2015	-	-	671	672	-	-	1,343
24	07480	Orange 66/12 kV Substation	Jun 2015	-	142	7,280	7,286	-	-	14,708
25	05411	Lakeview 115/12 kV Substation	Jun 2016	3,072	4,605	27,838	22,945	6,550	-	65,011
26	06067	Yokohl 66/12 kV Substation	Jun 2016	95	4,140	10,060	30,329	43,410	-	88,034
27	06619	Banducci 66/12 kV Substation	Jun 2016	2,252	2,830	5,353	21,257	10,413	-	42,105
28	06836	Greenhorn 66/2.4 kV Substation	Jun 2016	-	-	500	2,053	1,555	-	4,108
29	07293	Mainframe 66/4.16 kV Substation	Jun 2016	-	2,223	2,279	12,675	7,519	-	24,696
30	07516	Safari 33/12 kV Substation	Jun 2016	-	-	6,587	23,103	17,097	-	46,787
31	06575	Circle City 66/12 kV Substation - Phase 1	Jun 2016	-	724	5,687	14,140	4,647	-	25,198
32	05397	Falcon Ridge 66/12 kV Substation	Dec 2016	3,316	2,698	8,809	24,255	44,475	-	83,554
33		**Total Distribution Substation Plan**		155,694	102,329	133,621	163,212	135,666	-	690,522

The capital cost shown for each project in the table above is for work required inside the substation (e.g., the addition of a B-bank transformer), new distribution circuits associated with a B-bank transformer addition, and any telecommunications or right of way and land components of the project. The costs for the distribution circuits that are not associated B-bank transformer addition projects are aggregated and budgeted as a separate item entitled “DSP Circuits” and are included in this portion of my testimony for reference and justification purposes only. These circuit costs are discussed separately in the System Improvement/Reinforcements Program portion of my testimony.

We have identified 32 DSP projects with project costs equal to or greater than $1 million. A description and justification for each of these projects is provided below. The total cost for these 32 projects is $690.5 million of which $534.8 million is CPUC-jurisdictional cost forecast from 2013 to 2017.

APPENDIX C

PG&E Data Response TURN_045_Q04 in A.15-09-001 (TY 2017 GRC)

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase I
Application 15-09-001
Data Response

PG&E Data Request No.:	TURN_045-Q04		
PG&E File Name:	GRC-2017-PhI_DR_TURN_045-Q04		
Request Date:	February 5, 2016	Requester DR No.:	045
Date Sent:	February 23, 2016	Requesting Party:	The Utility Reform Network
PG&E Witness:	Satvir Nagra	Requester:	Marcel Hawiger

EXHIBIT REFERENCE: PG&E-4, CHAPTER 13

SUBJECT: ELECTRIC DISTRIBUTION CAPACITY

QUESTION 4

Please provide the list of projects included in PG&E's last rate case (2014) for the category "normal capacity deficiencies."

a. Are any projects included in this list also included in the list of projects for PG&E's 2017 GRC? If so, please explain why PG&E has included projects in this GRC from the last GRC.

ANSWER 4

Attachment GRC-2017-PhI_DR_TURN_045-Q04Atch01 includes Workpaper Tables 12-3, 12-7, and 12-8 that lists specifically identified projects in the 2014 GRC.

a. PG&E has included some projects in the 2017 GRC forecast that were also included in the 2014 GRC forecast. PG&E reprioritized the work across the Electric Distribution line of business. See PG&E's Opening Testimony for Exhibit (PG&E-4), Chapter 1, page 1-14 for a discussion of PG&E's reprioritization of spending within the Electric Distribution line of business. In addition, PG&E reprioritized resource allocation with MWC 46 and MWC 06 due to the increase in agricultural pumping requirements caused by the drought.

APPENDIX D

PG&E Data Response TURN_068_Q01_Atch02 in A.15-09-001 (TY 2017 GRC)

MWC 06 and 46 Projects included in the 2011 GRC also included in the 2017 GRC Project List

Order Number	MWC	Project Description	Basis for inclusion in the 2017 GRC	2017 GRC WP Table	Line No.
5734323	06	06-Shepherd Sub: Install New Feeders	New Substation, long lead project. Delayed due to land purchase and permitting.	13-3	5
5720078	46	46-Athens Substation Site Land Purchase	New Substation, long lead project. Completion date set as needed to support area capacity.	13-3	29
5707549	46	46-Windsor Sub: Land (Fulton DPA)	New Substation, long lead project. Delayed due to land purchase and Permit to Construct (PTC) permitting delay	13-3	36
5738568	46	Install Rincon Bank 3	Reprioritized for the 2017-2019 timeframe to fund higher priority work.	13-3	38
5733998	46	46-Install Ames Bank #2	Schedule changed to meet customer's timeline.	13-3	40
5734319	46	46-Gosford Sub: Build New Substation	New Substation, long lead project. Reprioritized due to delays in New Substation Land Permitting.	13-3	42
5734322	46	46-Shepherd Sub: Build New Substation	New Substation, long lead project. Delayed due to land purchase and permitting.	13-3	43
5733919	46	46-Replace Menlo Bank #1	Project schedule adjustment into the 2014-2016 time frame due to reprioritization.	13-3	45
5733933	46	46-Instll Nortch Bank 2 for Cisco System Exp	Schedule changed to meet customer's timeline.	13-3	47
5733970	46	46-Replace Mabury Bk 1	Project schedule adjustment due to reprioritization.	13-3	48
5736769	06	Replace Beresford Bk 2	Reprioritized to fund higher priority work.	13-10	3
5733917	06	Install Nord Bank #3	Minor carryover expenditure from past job	13-10	6
5733934	06	Replace Menlo Bank #1	Project schedule adjustment into the 2014-2016 time frame due to reprioritization.	13-10	9
5733965	06	Fulton DPA - Construct new Substation (Windsor)	New Substation, long lead project. Delayed due to land purchase and permitting.	13-10	12
5733967	06	Install Rincon Bank 3	Reprioritized for the 2017-2019 timeframe to fund higher priority work.	13-10	22
5734320	06	06-Gosford Sub: Install New Feeders	New Substation, long lead project. Reprioritized due to delays in New Substation Land Permitting.	13-10	28
5720079	06	06- Alleghany 1101 & 1102 Repl DiselGnrtr	Minor carryover expenditure from past job	13-10	33
5733061	6	06-Diablo: Extend Tassajara 2109 Circuit	Minor carryover expenditure from past job	13-10	73
5734004	06	Replace Mabury Bank 1	Project schedule adjustment due to reprioritization.	13-10	130
5721438	06	06-Larkin Add New Feeder	Schedule changed to meet customer's timeline.	13-10	148
5734006	06	Install Ames Bank #2	Schedule changed to meet customer's timeline.	13-10	153
5729178	46	46-North Coast Rincon: Replace Bnk/Feeder	Minor carryover expenditure from past job	13-10	159
5721544	46	46-Menlo: Replace 4 kV bank 1w/larger	Minor carryover expenditure from past job	13-10	160
5734547	46	46-Monroe Sub: Repl Bank #3, Add Feeder	Project schedule adjustment due to reprioritization.	13-10	163
5736697	46	Install Vasona new 12 kV feeder	Minor carryover expenditure from past job	13-10	165
5728878	46	46-Atwater Sub: Inst New Feeder	Minor carryover expenditure from past job	13-10	170
5727541	46	46-Brentwood Sub: Feeder	Minor carryover expenditure from past job	13-10	173
5728003	46	46-Middletown Sub: Instll Brkr New 1102 Fdr	Minor carryover expenditure from past job	13-10	174

MWC 06 and 46 Projects included in the 2011 GRC also included in the 2017 GRC Project List

Order Number	MWC	Project Description	Basis for inclusion in the 2017 GRC	2017 GRC WP Table	Line No.
5734530	46	46-Wolfe 1115 New Feeder	Minor expenditure, job in the process of being canceled. New Business customer canceled project.	13-10	196
5734001	46	46-Henrietta Sub: Install New Bank	Minor carryover expenditure from past job	13-10	197
5736734	46	Wolfe new feeder	Minor expenditure, job in the process of being canceled. New Business customer canceled project.	13-10	199
5731103	46	46-Install Pinehill substation	New Substation, long lead project. Completion date set as needed to support area capacity.	13-10	202
5733618	46	46-Estrella: Purchase Land for New Sub	New Substation, long lead project. Completion date set as needed to support area capacity.	13-10	204
5727178	46	Natividad Land Purchase project	New Substation; load forecast did not support project. No forecast in the 2017 - 2019 time period.	13-10	206
5721442	46	46-Mesa Sub: Install Distribution Bank	Minor carryover expenditure from past job	13-10	208
5738560	46	Beresford Substation: Replace Bank #2	Reprioritized to fund higher priority work.	13-10	211
5736762	46	Replace Vacaville Bank 1	Reprioritized for the 2017-2019 timeframe to fund higher priority work.	13-10	213
5733961	46	46-Replace Llagas Bank #2	Reprioritized for the 2017-2019 timeframe to fund higher priority work.	13-10	216
5729175	46	46-Sierra Browns Valley: Instll Bnk/Fder	Minor carryover expenditure from past job	13-10	220
5736684	46	Install Green Valley Bank 2	Project to support transmission line conversion, project team determined work was not required.	13-10	221
5726106	46	Chowchilla Sub: Repl Bnk 1	Minor carryover expenditure from past job	13-10	222
5734403	46	46-Newark Sub:Fremont 12kV DPA Capc Incr	Minor carryover expenditure from past job	13-10	224
5736717	46	Replace Jarvis Bank 2	Load forecast did not support capacity increase; this particular job was canceled.	13-10	225
5733991	46	Install Nord Bank #3	Minor carryover expenditure from past job	13-10	226
5722629	46	46-Ag-Ice Project- Repl Maridan Bank 1	Minor carryover expenditure from past job	13-10	227
5721859	46	46-Hick Sub: Inst Bnk 5	Minor carryover expenditure from past job	13-10	229
5729164	46	46-San Jose: Replace Sta A Bank #3	Minor carryover expenditure from past job	13-10	230
5727018	46	46-Willow Pass Sub: Inst 45 MVA Bank	Minor carryover expenditure from past job	13-10	231
5729162	46	46-Diablo Moraga: Install Bank/Feeder	Minor carryover expenditure from past job	13-10	232
5733239	46	46-Tassajara: WC21 DPA Capacity Increase	Minor carryover expenditure from past job	13-10	233
5734548	46	46-Lakewood: Walnt Crek 12 kV DPA Capacity	Minor carryover expenditure from past job	13-10	234