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Witness	:	T. Roberts

OFFICE OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Report on the Results of Operations for Pacific Gas and Electric Company Test Year 2017 General Rate Case

Electric Distribution Capital Expenditures
Part 1 of 2

San Francisco, California
April 8, 2016

TABLE OF CONTENTS

I. INTRODUCTION 1

II. SUMMARY OF RECOMMENDATIONS 1

III. GENERAL DISCUSSION 5

A. Use of 2015 Recorded Costs 5

B. Escalation 5

C. Attrition Years 2018 and 2019 5

D. Attachments to this Testimony 6

E. Workpapers Supporting this Exhibit 6

IV. ELECTRIC DISTRIBUTION CAPACITY PROGRAM 6

A. Overview of PG&E's and ORA's Forecasts 7

B. ORA's Analysis 9

1. Legislative and Regulatory Background 9

2. Non-DRP Related Capital Expenditures 11

3. DER Integration Capacity (DERIC) Program 15

a. The Legislative Intent of AB 327 17

b. The Guidance Provided in Current CPUC Proceedings 17

c. Distributed Energy Resources Interconnection Rules 20

d. Technical Aspects of Future Distributed Energy Resources Deployment 22

e. Need for the DERIC Program in 2017 22

4. Volt/ VAR Optimization Program 23

a. Justification for the Volt/Var Optimization Program 27

b. PG&E's Forecast of Net Benefits 28

c. Cost-effectiveness Findings from the Volt/Var Optimization Pilot Project 32

d. Smart Inverters 35

e. Communication with Smart Inverters 38

f. PG&E's Volt/ VAR Optimization Cost Estimates 40

C. Recommendations Regarding Distribution Resource Plan Related Expenditures 41

V. ELECTRIC DISTRIBUTION WORK REQESTED BY OTHERS – RULE 20A 44
A. Overview of PG&E's and ORA's Forecasts 44
B. Background on Rule 20A Work Credits 46
C. ORA's Analysis 49
D. Summary of Recommendations for Rule 20A Undergrounding Projects 55
VI. ELECTRIC WORK REQUESTED BY OTHERS 56
A. Overview of PG&E's and ORA's Forecasts 57
B. ORA's Analysis 57
VII. ELECTRIC NEW BUSINESS 57
A. Overview of PG&E's and ORA's Forecasts 57
B. ORA's Analysis 59
1. Residential Expenditures 59
2. Non-residential Expenditures 60
3. Line Extension Reporting Requirements 60
4. PEV Expenditures 61
5. Transformers 65
C. Recommendation Regarding Tracking MWC 16 Expenditures 67
VIII. WITNESS QUALIFICATIONS 68

ELECTRIC DISTRIBUTION CAPITAL EXPENDITURES
Part 1 of 2

I. INTRODUCTION

This exhibit presents the analyses and recommendations of the Office of Ratepayer Advocates (ORA) regarding Pacific Gas and Electric Company's (PG&E) forecasts of Electric Distribution capital expenditures for 2015 through Test Year (TY) 2017.

Electric distribution capital expenditures include plant investment in electric meters, distribution substations, underground cables, and replacing/reinforcing poles. Electric distribution capital includes projects to construct or modify facilities for the distribution of electricity (at voltages below 60,000 volts),[1] projects to construct or modify substations to transform transmission voltage to a lower distribution voltage, and projects to improve system reliability (including aging infrastructure issues).

This exhibit specifically addresses PG&E's forecasts associated with its Customer Connection, Demand Growth and Franchise Obligations program areas. All other Electric Distribution capital expenditure forecasts are addressed in Exhibit (Ex.) ORA-11 (Electric Distribution Capital Expenditures, Part 2 of 2).

II. SUMMARY OF RECOMMENDATIONS

The following summarizes ORA's recommendations regarding Electric Distribution capital expenditures for 2015-2017:

- Use 2015 recorded costs rather than PG&E's 2015 forecast, resulting in a 2015 capital expenditure forecast that is $22.0 million lower than PG&E's forecast for Major Work Categories (MWC) 6, 10, 16, 30, and 46;

[1] PG&E Electric Rule 2, sheet 2.

- PG&E's proposal for two new programs related to the Distribution Resource Planning (DRP) proceeding should be denied, which results in the following adjustments:
    - Expenditures for MWC 6 (Capacity Program, distribution lines) should be reduced by $22.2 million in 2017;
    - Expenditures for MWC 46 (Capacity Program, substations) should be reduced by $6.7 million in 2017;
    - Expenditures for MWC 2F (Capacity Program, Information Technology (IT)) should be reduced by $10.9 million in 2017;
- Capital expenditure forecasts for MWC 16 (New Business) should be $392.1 million in 2016, and $413.0 million in 2017, compared to PG&E's forecasts of $409.3 and $434.4 million respectively;
- Capital expenditure forecasts for MWC 30 (Work Requested by Others, Rule 20A) should be $47.7 in 2016, and $49.2 million in 2017, compared to PG&E's forecasts of $80.2 and $83.7 million respectively;
- DRP related expenditures should be consistent with the AB 327 and should not prejudge findings and orders in the DRP proceeding;
- Requests for ratepayer funding of proposed programs, such as the Distributed Energy Resources (DER) Integration Capacity program, should explicitly account for payments per Rule 21 or the Wholesale Distribution Tariff (WDT) from DER providers;
- Programs intended to integrate DER should be fully compatible with smart inverter functionality, both those adopted and those likely to be adopted;
- If the Commission elects to defer rather than deny the Volt/Var Optimization (VVO) program, the following should be incorporated:
    - Results from the VVO pilot program that have been vetted and considered within the context of PG&E's entire distribution system;
    - ORA recommended cost adjustments;
    - The Commission should investigate why PG&E is not currently required to implement conservation voltage reduction (CVR), and whether this condition is justified given the state's current policy goals;
    - The Commission should investigate if PG&E has requested and received funding for CVR is the past, and if it should already be implementing CVR without further ratepayer investments;

- Alternate conservation voltage reduction methods, including those used by Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E), need to be considered as alternatives to VVO;
- If new communication systems as the proposed Field Area Network (FAN) prove incompatible with smart inverters, then PG&E shareholders should bear the replacement burden;

- Cost effectiveness analyses should use the appropriate CPUC approved tests and input data;
- PG&E should prepare an annual report of all instances where DER is evaluated as an alternative to traditional capital investments, regardless of which type of investment is ultimately made;
- For MWC 46, PG&E should either structure its request in future GRCs based on MAT codes, or revise its MAT codes and accounting of expenditures so they are aligned with programs for which PG&E requests ratepayer funding.;
- The Rule 20A Annual Work Credit Allocation should be set to zero for 2017-2019, and reviewed for re-introduction in the 2020 GRC;
- PG&E's request to discontinue production of line extension reports per D.04-05-055 should be denied;
- A new Maintenance Activity Task (MAT) code should be established for transformer scrapping under MWC 16;
- Non-residential expenditure and connection data in MWC 16 should be provided at the MAT level.

Table 10-1 below compares recorded costs and ORA's and PG&E's 2015-2017 forecasts of Electric Distribution capital expenditures addressed in this exhibit:

Table 10-1
Electric Distribution Capital Expenditures
Customer Connection, Demand Growth and Franchise Obligations
(In Thousands of Dollars)

				1	2	3	4	5	6	7	8	9	10	11
				Recorded							Estimated			
Line #	Exhibit PG&E-4	MWC	MWC Description	2010	2011	2012	2013	2014	2015 [1]		2016		2017	
									PG&E	ORA	PG&E	ORA	PG&E	ORA
1	Chapter 13	6	E Distribution Line Capacity	$81,359	$90,130	$88,543	$81,112	$94,330	$93,114	$95,723	$91,411	$91,411	$115,775	$93,598
2		46	E Distribution Substation Capacity	$63,092	$63,009	$51,335	$57,584	$66,812	$54,804	$68,301	$65,792	$65,792	$85,160	$78,440
3		2F	Information Technology -VVO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,919	$0
4	Chapter 17	10	E Distribution WRO General	$64,975	$84,531	$108,855	$76,347	$79,722	$98,000	$93,335	$93,521	$93,521	$94,065	$94,065
5		16	E Distribution New Business Customer Connects	$180,936	$211,667	$235,527	$252,694	$320,817	$355,000	$355,443	$409,325	$392,111	$434,351	$413,041
6	Chapter 18	30	E Distribution WRO Rule 20A	$36,610	$33,628	$52,426	$69,378	$41,116	$76,000	$41,885	$80,184	$47,687	$83,740	$49,213
7			TOTAL	$426,972	$482,965	$536,686	$537,115	$602,797	$676,918	$654,688	$740,233	$690,522	$824,011	$728,357

Notes:
[1] For 2015, ORA's forecast uses 2015 recorded costs.
All data in this table is complied from more detailed tables from this exhibit, Ex. ORA-10.

III. GENERAL DISCUSSION

This section discusses ORA findings and recommendations that apply to all MWCs discussed in subsequent sections.

A. Use of 2015 Recorded Costs

ORA obtained PG&E's 2015 recorded expenditures from PG&E through discovery for all MWCs discussed in this exhibit.[2] ORA recommends the Commission use these values in lieu of PG&E forecast values. Table 10-1 above shows 2015 recorded expenditures. Throughout this exhibit, ORA uses 2015 recorded expenditures in lieu of providing an alternative 2015 forecast.

B. Escalation

PG&E applies the following annual escalation factors to electric distribution capital expenditures: 2.8% for 2016 and 3.2% for 2017.[3] In contrast, PG&E "committed to offset escalation for 2012 through 2015 by implementing productivity improvements and other initiatives associated with the Electric Operations Improvement Plan" and did not apply escalation to electric distribution capital expenditures the 2014 GRC.[4] In this exhibit, ORA applies PG&E's proposed escalation rates without adjustment.

C. Attrition Years 2018 and 2019

PG&E forecasts for 2018 and 2019 are not addressed in this exhibit. Ex. ORA-21 (Post-Test Year Ratemaking) provides ORA's post-test year ratemaking recommendations.

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[2] PG&E's response to DR-ORA-Oral025, Attachment 1.

[3] Ex. PG&E-4 work papers (WP), p. WP 19-33, line 40. Also note that cumulative escalation of 6.0% for 2017 is given in line 41.

[4] Ex. PG&E-4 of PG&E's 2014 GRC, A.12-11-009, p. 9-3. Also see p. 1-13 of the same exhibit.

D. Attachments to this Testimony

ORA performed extensive discovery to support this exhibit. All discovery materials cited herein are included as an attachment(s) to this exhibit as follows:

- Attachment 1: documents that materially impact ORA's forecasts and recommendations, including data request (DR) responses and attachments to DRs;
- Attachment 2: documents cited within this exhibit, but that do not materially impact ORA's forecasts and recommendations, including data request (DR) responses and attachments to DRs.

E. Workpapers Supporting this Exhibit

Workpapers supporting this exhibit are provided in the following files:

- Exhibit ORA-10 Workpapers, part 1.xls – Numbered tables included in testimony;
- Exhibit ORA-10 Workpapers, part 2.xls – ORA scenario analysis of the Volt/Var Optimization (VVO) program;
- Exhibit ORA-10 Workpapers, part 3.xls – Numbered figures related to MWC 30 Rule 20A Undergrounding program;
- Exhibit ORA-10 Workpapers, part 4.xls – Numbered figures related to MWC 16 Plug-in Electric Vehicle (PEV) program;

IV. ELECTRIC DISTRIBUTION CAPACITY PROGRAM

This section discusses PG&E's primary program to "to upgrade or install new substation and distribution line equipment to meet the loading capacity requirements for new and existing customers" which PG&E refers to as the Electric Distribution Capacity Program (Capacity Program).[5] Substation expenditures are captured in MWC 46 and distribution line expenditures in MWC 6. The Capacity Program as proposed includes upgrades based on forecasted load growth, existing sub-

[5] Ex. PG&E-4, p. 13-1. Electric distribution investments for line extensions to new customers, PEV related loads, and service transformers are included in Chapter 17 under MWC 16.

programs designed to improve system reliability,[6] and two new programs that are related to the concurrent Distribution Resource Plan (DRP) proceeding at the CPUC.[7]

ORA anticipated that the schedule overlap between the DRP application, which was filed July 1, 2015, and this GRC application, which was filed two months later on September 1, 2015, would result in GRC requests that both increased and decreased expenditure for the Capacity program. However, Chapter 13 of Ex. PG&E-4 provides an asymmetric showing where PG&E request additional funding for new programs to support Distributed Energy Resources (DER), but provides de minimus reductions in planned expenditures based on DER. This is not consistent with recent statutory and regulatory direction and prejudges the outcome of the active Distribution Resource Plan (DRP) proceeding. The DRP proceeding will be an opportunity for the Commission to provide identify benefits to ratepayers and ensure they are realized. Until that proceeding is concluded, expenditures for the Capacity Program should be limited to those required for safety and for maintaining existing capacity and reliability.

A. Overview of PG&E's and ORA's Forecasts

The following Table 10-2 summarizes historic expenditures, PG&E's request, and ORA's recommendation for PG&E's Electric Distribution Capacity program, Ex. PG&E-4, Chapter 13, which includes MWC 2F, 6, and 46 capital expenditures.

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[6] ORA considers the following subprograms related to grid reliability more so than meeting capacity: substation transformer emergency capacity, circuits with large numbers of customers, completion of mainline loops, and voltage complaints, as described in Ex. PG&E-4, pp. 13-17 to 13-25.

[7] PG&E DRP Application A.15-07-006, p. 202. PG&E also states that it "has piloted two programs to reduce peak demand through DER alternatives that could allow capital project expenditures to be rescheduled," Exhibit PG&E-4, p. 13-4, but it is not explicit in that section that Volt/Var Optimization is one of the two programs.

Table 10-2
Electric Distribution Capital Expenditures
Electric Capacity Program, Ex. PG&E-4 Chapter 13
(In Thousands of Dollars)

			1	2	3	4	5	6	7	8	9	10	11
Line #	MWC	MWC Description	Recorded[1]							Estimated[2]			
			2010	2011	2012	2013	2014	2015 [3]		2016		2017	
								PG&E	ORA	PG&E	ORA	PG&E	ORA
1	6	E Distribution Line Capacity	$81,359	$90,130	$88,543	$81,112	$94,330	$93,114	$95,723	$88,921	$88,921	$88,300	$88,300
2	6	E Distribution Line Capacity - DERIC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,070	$0
3	6	E Distribution Line Capacity - VVO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,852	$0
4	6	E Distribution Line Capacity - Escalation	$0	$0	$0	$0	$0	$0	$0	$2,490	$2,490	$5,298	$5,298
5	6	E Distribution Line Capacity - DERIC, Escalation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,024	$0
6	6	E Distribution Line Capacity - VVO, Escalation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$231	$0
7		TOTAL	$81,359	$90,130	$88,543	$81,112	$94,330	$93,114	$95,723	$91,411	$91,411	$115,775	$93,598
8	46	E Distribution Substation Capacity	$63,092	$63,009	$51,335	$57,584	$66,812	$54,804	$68,301	$64,000	$64,000	$74,000	$74,000
9	46	E Distribution Substation Capacity-DERIC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,165	$0
10	46	E Distribution Substation Capacity-VVO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,175	$0
11	46	E Distribution Substn. Capacity-Escalation	$0	$0	$0	$0	$0	$0	$0	$1,792	$1,792	$4,440	$4,440
12	46	E Distribution Substn. Capacity-DERIC Escalation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$250	$0
13	46	E Distribution Substn. Capacity-VVO, Escalation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$131	$0
14		TOTAL	$63,092	$63,009	$51,335	$57,584	$66,812	$54,804	$68,301	$65,792	$65,792	$85,160	$78,440
15	2F	Information Technology -VVO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,301	$0
16	2F	Information Technology -VVO, Escalation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$618	$0
17		TOTAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,919	$0
18		GRAND TOTAL	$144,451	$153,139	$139,878	$138,696	$161,142	$147,918	$164,024	$157,203	$157,203	$211,855	$172,038

Notes:
[1] Recorded data for 2010-2014 from PG&E WP Table 13-1.
[2] PG&E estimated data from PG&E WP Table 13-7.
[3] For 2015, ORA's forecast uses 2015 recorded costs from PG&E's response to DR-ORA-Oral-25.

B. ORA's Analysis

ORA's analysis focused PG&E's two new proposed programs: the Distributed Energy Resources Integration Capacity (DERIC) and the Volt/Var Optimization (VVO) programs.[8] Before the discussion of these programs, background on the legislative and regulatory context referenced by PG&E is provided, and well as placing these programs within the overall Capacity Program request.[9]

1. Legislative and Regulatory Background

Assembly Bill (AB) 327 (Perea), signed into law on October 7, 2013, addressed many natural gas and electricity matters related to the CPUC and regulated utilities.[10] One provision of AB 327 addressed the electric distribution planning process, and added Section 769 to the Public Utilities Code, which defines Distributed Energy Resources, and requires the utilities to create Distribution Resource Plans (DRP).[11] Numerous statements in the AB 327 signal the policy objectives for the utilities regarding the integration of Distributed Energy Resources (DER). Among them is the following:

> The Public Utilities Act requires each electrical corporation, as a part of its distribution planning process, to consider specified nonutility owned distributed energy resources **as an alternative to investments in its distribution system** to ensure reliable electric services at the lowest possible costs. This bill would require an electrical corporation, by July 1, 2015, to submit to the commission a distribution resources plan proposal, as specified, to **identify optimal locations for the deployment of distributed resources**, as defined. The bill would

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[8] ORA used the acronym "DERIC" in discovery and uses it in this exhibit. PG&E does not use this term in Ex. PG&E-4.

[9] Ex. PG&E-4, p.13-3, Figure 13-2.

[10] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327.

[11] Public Utilities Code Section 769 (a): For purposes of this section, "distributed resources" means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

> require the commission to review each distribution resources plan proposal submitted by an electrical corporation and approve, or modify and approve, a distribution resources plan for the corporation. The bill would require that any electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan be proposed and considered as part of the next general rate case for the corporation and would authorize the commission to approve this proposed **spending if it concludes that ratepayers would realize net benefits** and the associated costs are just and reasonable.[12]
>
> The commission shall review each distribution resources plan proposal submitted by an electrical corporation and approve, or modify and approve, a distribution resources plan for the corporation. The commission may modify any plan **as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources**.[13]
>
> Any electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan shall be proposed and considered as part of the next general rate case for the corporation. The commission may approve proposed spending **if it concludes that ratepayers would realize net benefits and the associated costs are just and reasonable**.[14]

This language clearly indicates the intention of the Legislature that the Distribution Resource Plans should result in deploying Distributed Energy Resources in "optimal" locations as a cost-effective alternative to traditional investments in substations and distribution lines.

The Commission opened Order Instituting Rulemaking (R.)14-08-013 to implement AB 327 and it stated the objective was that Distributed Energy Resources should be located to maximize cost-effectiveness:

> Integrate DERs into distribution system planning and operations; specifically, propose **cost-effective methods** of effectively coordinating

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[12] AB 327 introduction, emphasis added.

[13] Public Utilities Code Section 769(c), emphasis added.

[14] Public Utilities Code Section 769(d), emphasis added.

existing commission-approved programs, incentives, and tariffs to **maximize the locational benefits and minimize the incremental costs of distributed resources**.[15]

A significant component of the net benefit calculation will be whether deeper penetration of DER in a particular location or on a specific feeder will be able to provide an alternative to the most costly upgrades of distribution (or eventually transmission) facilities that might otherwise be necessary to meet load. **The deferral or avoidance of network upgrades may, in fact, offset much of the expected costs of accommodating new customer-side resources**.[16]

These quotations make clear that a goal of the Distribution Resource Plan process is for Distributed Energy Resources to be integrated cost-effectively, i.e. at net-ratepayer benefit, within the overall utility distribution planning process. ORA recommends that DRP related expenditures should be consistent with the AB 327 and should not prejudge findings and orders in the DRP proceeding

2. Non-DRP Related Capital Expenditures

ORA does not oppose PG&E's non-Distribution Resource Plan related Capacity Program requests except for the use of 2015 recorded expenditures, as discussed in Section III.A, and as shown in Table 10-2. However, ORA's analysis shows that Ex. PG&E-4 and its supporting workpapers provide no quantified reductions in expenditures or other quantified ratepayer benefits that could offset the costs of the two new proposed programs.[17]

In Ex. PG&E-4, PG&E makes multiple requests for expenditures to maintain or upgrade its electric distribution system. In Chapter 13 PG&E requests $93.6 million in 2017 for feeder upgrades, and $78.4 million for sub-station upgrades to

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[15] CPUC Order Instituting Rulemaking (OIR) decision for R.14-08-013, issued August 20, 2014, p.5, emphasis added.

[16] Assigned Commissioner's Ruling in R.14-08-013, dated February 06, 2015, p.4, emphasis added.

[17] As discussed in Section IV.B.4. below, PG&E quantified benefits for its proposed Volt/Var Optimization program.

increase capacity to meet customer demand.[18] While PG&E points to how existing Distributed Energy Resources are included in load forecasts, and refers to other proceedings in which projects were or could be "rescheduled,"[19] PG&E stated that it "has not undertaken a study to assess the magnitude of these rescheduled or avoided expenditures."[20]

In one case, PG&E refers to two feeder projects that were rescheduled under the Targeted Demand-Side Management (TDSM) pilot program, but in response to ORA discovery, PG&E only provided references to its work papers for one of the two feeders.[21] For this project at the Bogue substation, PG&E indicated that the project was rescheduled to 2020, but did not state when it was originally scheduled or the cost savings.[22] PG&E was supposed to track projects deferred from targeted Energy Efficiency (EE) efforts, but provided no evidence that any projects have been implemented, even though PG&E began the TDSM program in October 2013.[23]

In a second case, PG&E states that five distribution projects that "could potentially be rescheduled were identified in PG&E's 2014 Energy Storage Request for Offers (RFO) Application."[24] A review of PG&E's application in that proceeding, A.15-12-004, shows that only two of the five projects were selected by PG&E to

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[18] Ex. PG&E-4, p.13-1 and WP Table 13-7.

[19] Ex. PG&E-4, p. 13-6, FN 9. Also PG&E's response to DR-ORA-22-Q2.

[20] PG&E's response to DR-ORA-22-Q3.

[21] Ex. 4, p. 13-7, FN 10, and PG&E's response to DR-ORA-22-Q3.

[22] PG&E's response to DR-ORA-22-Q3, which refers to Ex. PG&E-4-WP, line 80, pp. 13-28 and 13-29.

[23] PG&E's response to DR-ORA-22-Q3 provides the initiation date of the PG&E" Targeted Demand Side Management Initiative" and pages 4, 6, and 9 of Attachment 1 to the DR discusses tracking requirements specified by D.14-10-046 OP 12c.

[24] Ex- PG&E-4, p. 13-7. The five projects are specified in FN 11.

submit for approval.[25] In addition, ORA and three other parties protested this application.[26] ORA is actively engaged in discovery and will file testimony on April 25, 2016 that will address whether the two remaining projects meet the cost effectiveness requirement of California Public Utilities Code Section 2835(a)(3)[27] and other criteria established by the Commission in D.14-10-045.[28]

A review of the Ex. PG&E-4 workpapers reveals that DER is used to justify expenditures, not as a justification for a quantified cost reduction or deferral.[29] While PG&E "is pursuing programs to identify locations where certain types of DER can avoid or delay investments in the distribution grid assets," these efforts have produced minimal if any justified and quantified benefits.[30] Ex. PG&E-4 reveals that for PG&E, DER is viewed as a problem that requires additional investment for

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[25] Application of Pacific Gas And Electric Company For Approval of Agreements Resulting From Its 2014-2015 Energy Storage Solicitation And Related Cost Recovery dated December 1, 2015, p. 5. The two projects still being considered are Mendocino and [Old] Kearney, which are listed as Purchase and Sale Agreement (PSA) projects in the second table on the referenced page. As explained on page 7 of the application, PSA projects "enable PG&E to defer the replacement of one or more transformers at a distribution substation." Energy Storage Agreement (ESA) projects, listed on the first table on page 5, are not distribution deferral projects, and were not part of the five projects mentioned in Ex. PG&E-4, p. 13-7.

[26] Protests were issued January 15, 2015 in A.15-12-004.

[27] "An "energy storage system" shall be cost effective and either reduce emissions of greenhouse gases, reduce demand for peak electrical generation, defer or substitute for an investment in generation, transmission, or distribution assets, or improve the reliable operation of the electrical transmission or distribution grid." (Emphasis added).

[28] A scoping ruling in A.15-12-004 was issued March 25, 2016 that schedules opening testimony on April 25, 2016.

[29] In Ex. PG&E-4, Chapter 13 workpapers, PG&E uses the following phrase repetitively, but with no specific projects cited as being deferred, and no cost reductions quantified: "Projects with forecast completion dates starting in 2017 and beyond will also evaluate a distributed energy resource (DER) alternative to determine cost and feasibility of peak demand reduction." See Ex. PG&E-4 -WP, pp. WP 13-62, WP 13-67, WP 13-72, and WP 13-91.

[30] PG&E's response to DR-ORA-22-Q1.

mitigation, rather than a solution as envisioned by the author of AB 327. For example:

> "PG&E is making distribution line and substation upgrades through its DER Integration Capacity Program to avoid negative effects on reliability, power quality and safety associated with DERs."[31]

> "Operation of the electric distribution system is becoming more complex with increasing customer demand for Distributed Energy Resources (DER) such as rooftop solar generation and energy storage. PG&E needs to deploy new tools, methodologies and technologies for use by operators, engineers and field employees to support the more complex operating environment."[32]

> "PG&E's SCADA platform is not adequate to support future growth or new features needed for the increasing amount of DER connecting to the distribution system."[33]

Independent of the issue of if and how PG&E has reduced expenditures based on its Distribution Resource Plan, ORA's analysis of MWC 46 expenditures was hindered by the fact that the Maintenance Activity Type (MAT) codes assigned do not correspond to the sub-programs discussed in the testimony and workpapers.[34] ORA recommends that in the next GRC, PG&E should either structure its request based on MAT codes, or revise its MAT codes and accounting of expenditures so they are aligned with programs for which PG&E requests ratepayer funding. ORA prefers the former alternative so that MAT codes provide a consistent tracking of cost for specific work types over time.

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[31] Ex. PG&E-4, p. 1-3.

[32] Ex. PG&E-4, p. 15-1.

[33] Ex. PG&E-4, p. 15-13.

[34] MAT codes for all electric distribution were provided as Attachment 1 to PG&E's response to DR-ORA-14-Q2. MWC subprograms are discussed in Ex. PG&E-4, pp. 13-14 to 13-18 and tabulated on page 13-20. No MAT numbers are provided.

3. DER Integration Capacity (DERIC) Program

PG&E requests $22.5 million in funding for a new Distributed Energy Resources Integration Capacity (DERIC) program starting in 2017 to support increasing penetration of renewable DER within its distribution system. The program would replace or upgrade specific types of equipment in substations and individual feeders to "handle the two-way flow of power."[35] "PG&E's methodology for determining DER Integration Capacity upgrades is to identify specific areas where DER growth exceeds integration capacity."[36] PG&E claims the program is "consistent with California policy as described in Assembly Bill (AB) 327 and Commission Rulemaking 14-08-013."[37]

PG&E's request should be denied. The proposed Distributed Energy Resources Integration Capacity program is inconsistent with AB 327 and R.14-08-013 and prejudges the outcome of an active and divisive proceeding. In short, DERIC strives to use Distributed Energy Resources as a tool to <u>increase</u> distribution expenditures rather than to <u>reduce</u> them as intended by the Legislature and the CPUC. In addition to the failing of this program to reduce costs, the following sections discuss issues related to interconnection rules and emergent technologies that support denial of this new program. Finally, PG&E has provided insufficient information to evaluate if this program is needed beginning as proposed in 2017.

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[35] Ex. PG&E-4, p. 13-31. Specific equipment, including substation relays, protection devices, feeder conductors, voltage regulators, and capacitor banks are discussed on pages 13-31 to 13-34 and WP Table 13-24.

[36] Ex. PG&E-4, p. 13-31.

[37] Ex. PG&E-4, p. 13-29.

Table 10-3
Electric Distribution Capital Expenditures
Distributed Energy Resources Integration Capacity (DERIC) Program
(In Thousands of Dollars)

Line #	MWC	MWC Description	1	2	3	4	5	6	7	8	9	10	11
			Recorded[1]							Estimated[2]			
			2010	2011	2012	2013	2014	2015 [3]		2016		2017	
								PG&E	ORA	PG&E	ORA	PG&E	ORA
1	6	E Distribution Line Capacity - DERIC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,070	$0
2	46	E Distribution Substation Capacity-DERIC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,165	$0
3	6	E Distribution Line Capacity - DERIC, Escalation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,024	$0
4	46	E Distribution Substn. Capacity-DERIC, Escalation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$250	$0
5		TOTAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$22,509	$0

Notes:
[1] Recorded data for 2010-2014 from PG&E WP Table 13-1.
[2] PG&E estimated data from PG&E WP Table 13-7.
[3] For 2015, ORA's forecast uses 2015 recorded costs from PG&E's response to DR-ORA-Oral-25.

a. The Legislative Intent of AB 327

PG&E's justification for this program is to provide consistency with AB 327.[38] Numerous statements in AB 327, as summarized in Section IV.B.1 above, indicate that the Distribution Resource Plan should result in deploying Distributed Energy Resources in "optimal" locations as a cost-effective alternative to traditional investments in substations and distribution lines. In contrast, the proposed Distributed Energy Resources Integration Capacity program result in more traditional investments in substations and distribution lines, increasing ratepayer investment, based on a claim that DER will result in reliability problems during 2017-2020.[39] As discussed in the next section, PG&E has not provided the required cost-effectiveness showing and therefore cannot demonstrate that the proposed program is consistent with AB 327.

b. The Guidance Provided in Current CPUC Proceedings

Section IV.B.1 above shows that CPUC proceeding R.14-08-013 also had the objective that Distributed Energy Resources should be located to maximize cost-effectiveness. For most of the cost-effectiveness tests used by the CPUC, the primary benefit is "utility avoided costs."[40] Therefore, Distributed Energy Resources can only be cost effective by most measures if the utility avoids or defers expenses or investments, such as upgrades to the distribution system. PG&E should be familiar with CPUC cost–effectiveness tests since it provided a benefit-to-cost

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[38] Ex. PG&E-4, p.13-29.

[39] PG&E response to DR-ORA-200-Q2.

[40] Cost effectiveness tests for DER are provided in the California Standard Practice Manual (SPM), Economic Analysis Of Demand-Side Programs And Projects dated October, 2001. For four of the five tests in the SPM "Utility avoided supply (UAC) costs" is a benefit: the Ratepayer Impact Measure (RIM) test, the Societal Test, the Total Resource Cost (TRC) Test, and the Program Administer Cost (PAC) Test. "Deferral or avoidance of network upgrades" as referenced above is an element of a UAC costs. For the Participant Test, "Bill reductions" is a benefit that is partially driven by utility cost reductions, but is primarily due to reduced use of grid provided energy and the associated utility bills.

analysis to support its request for the proposed VVO program. But PG&E provided no such analysis to support its DERIC request. This is inconsistent with AB327 and CPUC guidance in the Distribution Resource Plan proceeding.

In addition, an Assigned Commissioners Ruling (ACR) in R.14-08-013 directed the utilities to file their first DRPs by July 1, 2015, and said that these should include two analytical tools: an Integration Capacity Analysis (ICA) to "specify how much DER hosting capacity may be available on the distribution network," and an Optimal Location [net] Benefit Analysis (LNBA) to "specify the net benefit that DERs can provide in a given location."[41] PG&E has used a version of the DRP ICA tool to identify the scope of DERIC:

> Using the DER geo-spatial growth scenarios proposed in its DRP and subject to Commission approval of the DRP, PG&E will identify target areas where additional Integration Capacity is required to accommodate expected DER growth and promote two-way power flow during the 2017 GRC cycle.[42]

PG&E's DRP application notes that the Integration Capacity Analysis results are not a conclusive basis for making hardware upgrades: a substation with insufficient integration capacity "<u>may</u> be causing issues or is <u>likely to have</u> required mitigations due to interconnection" and that "substations and feeders that have low and/or negative [integration capacity factor] ICF values would be monitored to determine if any corrective actions need to be implemented."[43] Even if PG&E's Integration Capacity Analysis tool were vetted and approved by the CPUC, these statement indicate that the near-term action would be monitoring, not equipment replacement. However, the DRP proceeding is currently active and there have been no rulings or decisions regarding the adequacy of PG&E's ICA tool. ORA is an

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[41] Assigned Commissioner Ruling dated February 6, 2015, in R.14-08-013, Attachment, pp. 3-4.

[42] Ex. PG&E-4, p.13-29. Ex. PG&E-4 and its workpapers do not specify particular projects, but these were provided in PG&E's response to DR-ORA-22-Q5, revision 1, Attachment 1.

[43] A.15-07-006, p.51.

active participant in the Distributed Energy Resources Plan proceeding and does not believe CPUC approval of PG&E's current DRP and Integrated Capacity Analysis to be *a fait accompli* based on a recently filed workshop report that stated "ICA methodologies are not yet approved and stakeholders should not have an expectation of accuracy for commercial decision-making."[44] ORA is particularly concerned that the Distribution Resource Plan process to date has not provided the transparency required to determine the accuracy and level of "conservatism" embedded in the Integrated Capacity Analysis.[45] Post-workshop comments from multiple parties are critical of PG&E's ICA tool.[46]

Finally, the assigned commissioner's ruling in R.14-08-013 signaled that the first Distribution Resource Plans filed July 1, 2015 were not assumed to provide a final or complete analysis, but rather the first step on a procedural journey:

> [O]ne of the most important recommendations of this guidance document is for the Commission and IOUs to adopt a biennial DRP filing cycle as part of the ratification of the Utility DRP Applications. Each iteration of the process will move California further down a path toward deeper penetration of DER, more effective analysis of where DER provides the most value to customers and to the electric distribution system, and a greater understanding of the policy framework that is necessary to achieve these goals.[47]

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[44] Administrative Law Judge Ruling dated February 18, 2016 in R.14.08-013, Attachment A, Joint IOU Workshop Report, p. 3.

[45] Conservatism in this instance refers to setting low integration capacity limits where DER could cause issues with the distribution system, but also may not, based on how actual circuits and loads compare to the assumptions used in the ICA. For example, see Attachment B of ORA's comments dated March 3, 2016 in R.14-08-013 for a critique of the current ICA tools, including PG&E's.

[46] Comments were filed March 3, 2016 in R.14.08-013.

[47] Assigned Commissioner Ruling dated February 6, 2015, in R.14-08-013, p.5.

> With this in mind, the DRP process should be a living one, where the Commission, the Utilities and stakeholders engage continuously to refine the activities and goals that are central to the DRPs themselves.[48]

The Commission thus anticipated that development of a distribution planning process that accommodated Distributed Energy Resources growth, consistent with the intent of AB327 would be an ongoing and interactive process, and defined three phases of the development through "2018 and beyond."[49]

PG&E's GRC proposal for its Distributed Energy Resources Integration Capacity uses a preliminary, untested, and unapproved version of its proposed ICA tool to define integration capacity constraints and then uses these questionable results as a justification for specific substation and distribution line upgrades. This prejudges the outcome of the Distribution Resource Plan proceeding and should not be used as the basis for expenditures in this proceeding.

One sign that PG&E's Integration Capacity Analysis tool is still evolving is shown by comparing the list of projects used to determine the scope of the DERIC program with a table from PG&E's Distributed Resources Plan application of the most highly penetrated [by DER] substations. The DERIC list includes no projects for two of the three most highly penetrated substations, yet includes many projects for substations that were not listed in the DRP table.[50]

c. Distributed Energy Resources Interconnection Rules

Distributed Energy Resources that can operate as a generator, such as roof-top solar, must follow the Rule 21 Tariff for retail customers, or the Wholesale

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[48] Assigned Commissioner Ruling dated February 6, 2015, in R.14-08-013, Attachment, p.11.

[49] Assigned Commissioner Ruling dated February 6, 2015, in R.14-08-013, Attachment, p.12.

[50] DERIC projects are listed in Attachment 1 to PG&E's response to DR-ORA-22-Q5. Highly penetrated substations are listed on page 57 of PG&E's DRP application, A.15.07-006. DERIC projects are not listed for the Buck's Creek or Kanaka substations, but are listed for Annapolis and Bangor substations.

Distribution Tariff (WDT) for wholesale customers.[51] Net Energy Metering (NEM) customers are interconnected under the Electric Rule 21 tariff.[52] With the exception of NEM customers, Distributed Energy Resource generators are generally responsible for distribution grid upgrades to mitigate any reliability or safety problems they create, as determined by PG&E interconnection studies.[53]

In response to ORA discovery in this GRC, PG&E indicated that it is not currently experiencing problems due to Distributed Energy Resources, but that it forecasts such problems within 2017-2019.[54] PG&E proposes it Distributed Energy Resources Integration Capacity program to mitigate the incremental impacts of new DER on top of existing DER. PG&E does not discuss the extent to which these new generators interconnect via Net Energy Metering, Rule 21 other than NEM, or WDT, is a transparency issue. ORA recommends that any requests for ratepayer funding of interconnection costs include estimates of contributions by DER developers.

If, as it appears, PG&E's proposed DERIC program shifts the costs for mitigation of interconnection issues from Distributed Energy Resource developers to ratepayers, PG&E's attempted-socialization of costs is neither recommended nor contemplated in either AB 327 or R.14-08-013. PG&E's Distributed Energy Resources Integration Capacity proposal should be denied. ORA recommends that requests for ratepayer funding of proposed DRP related programs, such as the Distributed Energy Resources Integration Capacity program, should explicitly account for payments per Rule 21 or the Wholesale Distribution Tariff (WDT) from DER providers.

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[51] PG&E's response to DR-ORA-200-Q13.

[52] PG&E's response to DR-ORA-200-Q14.

[53] PG&E's responses to DR-ORA-200-Q14 and Q16. Under the NEM successor tariff, per D.16-01-044, generators will still not be required to pay for distribution upgrades. See PG&E's response to DR-ORA-200-Q15.

[54] PG&E's responses to DR-ORA-200-Q1 and Q2.

d. Technical Aspects of Future Distributed Energy Resources Deployment

PG&E says its Distributed Energy Resources Integration Capacity program is designed to address potential distribution system problems attributable to DER.[55] The program fails to address the fact the a vast majority of DER connects to the grid through DC/AC inverters (inverters), that some "smart inverter" functions have been approved by the CPUC, and that other smart inverter functions are planned to help integrate DER.[56] This is addressed in greater detail in Section IV.B.4. below for the Volt/Var Optimization program, but the fact that a DER solution, i.e. mitigations provided by smart inverters, will be deployed in concert with DER, the purported problem, must be addressed in all discussion of potential DER-induced problems. PG&Es request for the DERIC program does not discuss the impact of smart inverters. ORA recommends that programs intended to integrate DER should be fully compatible with smart inverter functionality, both those adopted and those likely to be adopted.

e. Need for the DERIC Program in 2017

PG&E's testimony and workpapers lack details essential to determining if the program scope is reasonable. In addition to the Rule 21 issue raised in Section IV.B.3.c. above, Exhibit PG&E-4 provided negligible information on the Distributed Energy Resources growth scenario it used, the criteria and methodology used to determine the integration capacity, or the specific projects that support the requested scope of work.[57]

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[55] Ex. PG&E-4, p. 1-3, " PG&E is making distribution line and substation upgrades through its DER Integration Capacity Program to avoid negative effects on reliability, power quality and safety associated with DERs."

[56] Smart Inverters add additional features to aid in the integration of DER, beyond the basic function of converting voltage from DC to AC. These features are discussed in Section IV.B.4.d.

[57] Assigned Commissioner Ruling dated February 6, 2015, in R.14-08-013, Attachment, p.5, included three DER growth scenarios: trajectory, high growth, and very high potential growth.

In a data request, ORA asked: "Does PG&E forecast that it will experience problems with its distribution system and/or backflow to the transmission system based on DER during the 2017-2019 timeframe? If so, explain and **provide all reports, memos, or other documents that quantify these problems and show where they are expected to occur**."[58] PG&E's response provided no support for its assertion that "Yes, PG&E does forecast issues on its electric distribution system based on Distributed Energy Resources (DERs) during the 2017-2020 timeframe." ORA also asked for the DER forecast upon which the DERIC program was based, but PG&E's response did not specify which of the three Distribution Resource Plan growth scenarios was used.[59] PG&E also failed to provide some unit costs for the Distributed Energy Resources Integration Capacity cost estimate, and provided no support for the unit costs it did identify, even when asked for the information directly.[60]

4. Volt/ VAR Optimization Program

PG&E's proposed new Volt/VAR Optimization (VVO) program is the second of the two "DRP related investments to be included in PG&E's 2017 GRC."[61] PG&E states that the proposed new VVO program "will enable PG&E to monitor and

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[58] DR-ORA-200-Q2, emphasis added.

[59] PG&E's response to DR-ORA-200-Q8.

[60] Unit costs for Chapter 13 are provided in Ex. PG&E 4-WP, WP Table 13-15. This table does not include all the unit costs for DERIC shown in WP Table 13-24, including line 5 for installing SCADA. Also, many of the specific cost in WP Table 13-24 do not agree with WP Table 13-15, for example feeder breakers are $805,000 in the former but $600,000 in the later. DR-ORA-22-Q12 raised this issue, but PG&E's response pointed to its response DR-ORA-14-Q10, which does not provide the missing unit costs, and provides none of the support for WP Table 13-15 requested.

[61] PG&E DRP Application A.15-07-006, p. 202. PG&E also states that it "has piloted two programs to reduce peak demand through DER alternatives that could allow capital project expenditures to be rescheduled," Exhibit PG&E-4, p. 13-4, but it is not explicit in that section that VVO is one of the two programs.

control voltage along feeders in real-time, so that voltage can be optimized."[62] PG&E further explains that "if voltage is too high or too low, customers' electric devices will not work properly and could be damaged. Voltage that is too high leads to inefficient use of power."[63] As proposed, Volt/VAR Optimization would be implemented on 228 distribution feeders across PG&E's service territory during 2017-2019, with no proposed capital expenditures for 2015 and 2016. This is roughly 7 percent of PG&E's approximately 3,200 feeders.[64] PG&E estimates capital expenditures for this scope of work at $17.3 million, $34.0 million, and $32.4 million in 2017 to 2019, respectively, to install remote-controllers on existing voltage control devices (e.g., capacitor banks, LTCs, and voltage regulators), establish communications with these devices via communications networks, and install IT applications and hardware.[65] PG&E also requests 2017 expenses of $1.650 million for IT applications and operation of the VVO system on an ongoing basis.[66]

PG&E's primary justification for the program is a forecast benefit- to- cost ratio of 1.3 to 2.1.[67] PG&E also says its VVO pilot project is presently in Phase 2 field trials.[68] As discussed below, ORA has determined that PG&E's forecast benefit- to- cost ratios are unrealistically higher, and that PG&E has provided insufficient information to show that the proposed program can be integrated with smart inverter features adopted by the CPUC and those that are still pending

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[62] Ex. PG&E-4, p. 13-38.

[63] Ex. PG&E-4, p. 13-37.

[64] Ex. PG&E-4, p. 13-38.

[65] Ex. PG&E-4, p. 13-42, Table 13-6.

[66] Ex. PG&E-4, p. 13-41, Table 13-5, line 6, and p. 13-43. VVO expenses are addressed in Ex. ORA-9 (Electric Distribution Expenses.)

[67] Ex. PG&E-4, p. 13-39.

[68] Ex. PG&E-4, p. 13-38.

adoption. ORA recommends that PG&E's requested funding be denied in this GRC, as shown in Table 10-4.

Table 10-4
Electric Distribution Capital Expenditures
Volt/Var Optimization (VVO) Program
(In Thousands of Dollars)

			1	2	3	4	5	6	7	8	9	10	11
			Recorded[1]							Estimated[2]			
Line #	MWC	MWC Description	2010	2011	2012	2013	2014	2015 [3]		2016		2017	
								PG&E	ORA	PG&E	ORA	PG&E	ORA
1	6	E Distribution Line Capacity - VVO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,852	$0
2	46	E Distribution Substation Capacity-VVO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,175	$0
3	2F	Information Technology -VVO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,301	$0
4	6	E Distribution Line Capacity - VVO, Escalation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$231	$0
5	46	E Distribution Substn. Capacity-VVO, Escalation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$131	$0
6	2F	Information Technology -VVO, Escalation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$618	$0
7		TOTAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,308	$0

Notes:
[1] Recorded data for 2010-2014 from PG&E WP Table 13-1.
[2] PG&E estimated data from PG&E WP Table 13-7.
[3] For 2015, ORA's forecast uses 2015 recorded costs from PG&E's response to DR-ORA-Oral-25.

If, however, the Commission is inclined to approve ratepayer funding of a version of this this program in 2018 or 2019 based on the results of the VVO Pilot Project, ORA recommends cost reductions to PG&E's forecasts.

a. Justification for the Volt/Var Optimization Program

In its testimony, PG&E does not argue that it is currently experiencing problems with Electric Rule 2 voltage compliance. Nor do PG&E's workpapers provide any evidence that voltage violations are occurring in PG&E's system.

Instead, PG&E justifies the program as a continuation of a smart grid pilot, and one that offers benefits from energy savings that exceed the cost of implementing and operating the program.[69] Here, unlike with the Distribution Energy Resources Integration Capacity program, PG&E's testimony appears consistent with the cost-effectiveness test requirements of AB 327 and the Distribution Resource Planning proceeding. PG&E uses a benefit- to- cost (aka cost-effectiveness) test to compare Volt/ VAR Optimization program forecast benefits to forecast costs.[70]

In testimony, PG&E says that other utilities have Volt/ VAR Optimization, or have plans to deploy VVO, implying that this is an additional justification for the program.[71] However, through discovery ORA learned that "VVO is not expected to always have a benefit/cost ratio greater than 1"and that the cost-effectiveness depends on the technical details of each feeder (e.g., operating voltage, number of voltage control devices installed, existence of a communication network like SCADA)

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[69] Ex. PG&E-4, pp. 13-38 to 13-39.

[70] PG&E includes benefits for avoided energy, capacity, and greenhouse gas (GHG) emissions. See Ex. PG&E-4-WP, WP Table 13-21.

[71] Ex. PG&E-4, p. 13-39: "Industry benchmarking shows that many other utilities are deploying VVO. Southern California Edison, Commonwealth Edison, Duke Energy, Oklahoma Gas & Electric, and American Electric Power are presently deploying VVO, or have plans to do so."

and customer loads.[72] Therefore, the cost-effectiveness of Volt/Var Optimization programs is system specific, and claims of cost-effectiveness for other utilities can only be applied to PG&E once the systems and operating standards are shown to be equivalent. PG&E was not able to provide this information in response to discovery, so claimed results for other utilities cannot be used to justify PG&E's proposed program.[73]

b. PG&E's Forecast of Net Benefits

As previously discussed, justification for the proposed program hinges on PG&E's forecast of cost-effectiveness or that the program will produce net –benefits. PG&E's analysis is based on the quantification of only one assumed benefit of the Volt/Var Optimization program: VVO systems allow PG&E to lower the operating voltage of selected feeders, and as a result customers on these feeders consume less energy.[74]

ORA's discovery and analysis revealed a number of issues with the PG&E's VVO benefit-to-cost analysis. First, as a result ORA discovery, PG&E discovered that the stated benefit-to-cost ratio range of 1.3 to 2.1 is inaccurate and PG&E's corrected values are 1.12 to 1.98.[75]

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[72] PG&E's response to DR-ORA-185-Q2.

[73] DR-ORA-19-Q4 asked PG&E to "Provide all documents, data, and analysis supporting the statement "Many of these utilities have seen benefits similar to the benefits forecast that supports PG&E's proposed VVO Deployment" on page 13-39." PG&E's response included a high-level report as Attachment 1 that included no utility specific data, much less feeder-level comparisons.

[74] PG&E discusses other benefits of the VVO program in testimony, but these are not quantified or included in the calculated benefit to cost ratios. See PG&E's response to DR-ORA-19-Q7. Reduced customer energy consumption also reduces overall demand for electricity, and this benefit is included in PG&E's analysis.

[75] PG&E's second supplemental response to DR-ORA-19-Q6. PG&E testimony states the ratio ranges from 1.3 to 2.1, but Ex. PG&E 4-WP, WP Table 13-21 show the range as 1.3 to 2.2.

Second, PG&E's analysis incorrectly attributes benefits to VVO that should properly be attributed to a longstanding statewide program known as Conservation Voltage Reduction (CVR). CVR is the process of operationally limiting voltage on feeders for the purpose of reducing energy consumed by customers. PG&E has used conservation reduction voltage in varied forms since the 1970s,[76] and in its current form, CVR establishes customer voltage levels at or below the nominal service voltage. So for example, a 120 volt service would receive voltage in the range of 114 to 120 volts under CVR. Conservation reduction voltage is established in the Electric Rule 2 filing for each utility, and while San Diego Gas and Electric (SDG&E) and Southern California Edison (SCE) and both require CVR for all residential and commercial customers,[77] PG&E allows voltages higher than nominal (i.e. 126 volts for 120 volt nominal service) unless it deems the lower voltage is "practicable."[78] ORA is actively researching the genesis of PG&E's "at will" implementation of CVR, and how SCE and SDG&E are currently achieving system wide CVR. ORA recommends that evaluation of PG&E's proposed VVO program must consider alternative approaches to limit customer voltage, including those currently in use at SDG&E and SCE. This is supported by a statement by PG&E

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[76] PG&E's response to DR-ORA-19-Q3.

[77] SCE Electric Rule 2, sheet 2 dated May 11, 1998 section B.2.a. SDG&E Electric Rule 2 sheet 1 dated August 28, 2002 Section B.2.a. Both SCE and SDG&E allow higher than nominal voltages, i.e. 126 volts for 120 volt nominal service, for industrial and agricultural customers.

[78] PG&E Electric Rule 2, sheet 4 dated Jul 2, 1996: "For purposes of energy conservation, PG&E's distribution voltage will be regulated to the extent practicable to maintain service voltage on residential and commercial distribution circuits within the minimum and maximum voltages specified above for Class A circuits. The residential and commercial distribution circuits that cannot be operated within the minimum and maximum voltages for Class A circuits shall be regulated to the extent practicable to maintain service voltage within the minimum and maximum voltages for Class B circuits and, whenever possible, within the minimum and maximum voltages for Class A circuits. Also, PG&E's response to DR-ORA-185-Q5 states "PG&E operates all circuits at the lowest practicable peak voltage in accordance with Electric Rule 2."

that "VVO is not expected to always have a benefit/cost ratio greater than 1, and may not always be favorable to alternative investments in conservation."[79]

ORA discovery found numerous indications that PG&E's cost effectiveness analysis assumes that it does not currently operate conservation reduction voltage for any customers:

- The report that "PG&E believes [ ] provides the clearest overview of performance results from VVO pilots"[80] is actually a review of conservation reduction voltage entitled "National Assessment of CVR,"[81]
- "PG&E does not track the number of customers with and without CVR."[82]
- A progress report dated June 10, 2015, illustrates VVO as reducing voltages from up to 126 volts, above its CVR upper voltage limit of 120 volts, to less than 120 volts, which is within this range.[83] In other words, PG&E showed that the VVO pilot was being performed on feeders that were not being operated with CVR before the pilot.

By assuming that CVR is not being implemented in PG&E's service territory, PG&E's analysis is able to claim greater voltage reductions, and greater benefits, using 126 volts as the baseline maximum voltage as opposed to 120 volts.

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[79] PG&E's response to DR-ORA-185-Q2.

[80] PG&E's response to DR-ORA-19-Q4. Report provided as Attachment 1 to this response.

[81] PG&E's response to DR-ORA-19-Q4, Attachment 1. This report discussed Conservation Voltage Reduction generally, and the value of "deeper CVR" such as Volt/ VAR Optimization which requires additional investments at a cost of up to nearly 5 cents per kWh. Slides are not numbered, but this is the final chart in section 1 of the slide deck. One observation from this report states "Other than the work performed under the Pacific Northwest Distribution Efficiency Initiative, which is 7 years old [in 2014], there is little data on incremental costs of achieving deeper CVR savings" and "more data needs to be collected on CVR incremental costs and benefits." See the second slide in the section 4 of the slide deck. The report concludes with observations and recommendations that all refer to Conservation Voltage Reduction, not Volt/VAR Optimization.

[82] PG&E's response to DR-ORA-185-Q4.

[83] PG&E's response to DR-ORA-19-Q15, Attachment 2, slide 5.

Third, PG&E's forecast benefits for the program hinge on the assumption that the program will result in customer energy savings ranging from 1.8% to 2.85%.[84] This savings level is higher than a PG&E report on the first phase of the VVO Pilot which stated that Volt/ VAR Optimization "has the **promise** to deliver 1-2% reduction in energy demand and consumption."[85] The energy savings level used by PG&E in its benefit-to-cost analysis for the proposed VVO program is also at the high end of PGE's review of benchmark studies.[86]

Finally, PG&E's cost-effectiveness forecast assumes that a VVO system will produce benefits that exceed the cost of installing and commissioning the new VVO system on at least 228 feeders. PG&E's cost-effectiveness model calculates a benefit-to-cost ratio (BCR) at a feeder level, and the analysis for its "High Benefit Scenario" indicates a ratio greater than 1 (i.e. benefits exceed costs) for approximately 290 feeders.[87] However in response to discovery, PG&E indicated the following:[88]

- "The benefits of Volt/VAR Optimization (VVO) are not evenly distributed across PG&E's system;"
- "VVO is not expected to always have a benefit/cost ratio greater than 1;"

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[84] Ex. PG&E-4-WP, WP Table 13-21 line 1 shows the low scenario assumes 3% voltage reduction and CVR ratio of 0.6 for a 1.8% consumption reduction. Line 2 of this table shows the high scenario assumes 3.8% voltage reduction and CVR ratio of 0.75 for a 2.85% consumption reduction. This calculation is shown by PG&E in Attachment 2 to DR-ORA-19-Q15, slide 16.

[85] PG&E's Response to ORA-19-Q15, Attachment 2, slide 5, emphasis added.

[86] Ex. PG&E-4-WP, WP Table 13-22 shows a % energy reduction range from 0.8% to 3.0%, but per footnote 1 to this table, this data refers to CVR programs, not VVO programs.

[87] ORA review of PG&E's response to DR-ORA-19-Q6, Supplement 2, Attachment 1. Column "H" of the "Summary" tab provides the feeder ranked BCR for each feeder.

[88] PG&E's responses to DR-ORA-185-Q2 and Q3.

- "If the feeders with highest benefit to cost are targeted first, then the average benefit to cost for the Volt/VAR Optimization (VVO) program will decrease with each subsequent feeder;"
- "As part of the VVO Pilot, PG&E is refining the estimate of feeder-specific benefit/cost ratio for the feeders most likely of having favorable benefit/cost."

Therefore cost–effectiveness for the program depends on how well VVO performs on individual feeders, and the feeder level benefits produced. PG&E's cost-effectiveness model using its "Low Benefit Scenario" indicates a ratio greater than 1 (i.e. benefits exceed costs) for only 65 feeders.[89] In this scenario, fixed costs, such as $4.9 million in non-recurring "Security/Risk" expenditures, are spread over a lower number of benefit-producing feeders which exacerbates the portfolio level decline in cost-effectiveness, from 1.98 to 1.12.[90] More generally, the impact of significant fixed costs to install VVO hardware and software, independent of the number of feeders upon which the system is ultimately deployed, amplifies the impact of any errors in PG&E's cost-effectiveness forecast.

c. Cost-effectiveness Findings from the Volt/Var Optimization Pilot Project

PG&E reported that one outcome of Phase 2 of the Volt/ VAR Optimization Pilot is to "provide actual measured field benefit information to be used in determining the cost-effectiveness of a wider scale deployment."[91] The Volt/ VAR Optimization Pilot was designed to produce favorable results (i.e., that VVO systems produce significant benefits through energy savings): "the present 12 feeders selected based on preference for shorter, highly loaded, moderately complex, urban

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[89] ORA review of PG&E's response to DR-ORA-19-Q6, Supplement 2, Attachment 1. Column "H" of the "Summary" tab provides the feeder ranked BCR for each feeder.

[90] Ex. PG&E-4-WP, WP Table 13-16, line 8.

[91] Page 4 of PG&E Advice Letter 4528-E, Report on Phase 1 of the SmartGrid VVO pilot.

feeders where **likelihood of achieving customer CVR benefits is very high**."[92] In addition, ORA discovery revealed that the pilot project was performed on feeders operating without CVR, which further increases the opportunity for VVO to produce benefits, as previously discussed.[93] These biases towards high benefit circuits must be addressed when attempting extrapolate results from the pilot project to a wide scale program.

ORA obtained preliminary results based on 2015 Volt/VAR Optimization operations during the pilot project. The consultant's report provides preliminary Volt/VAR Pilot Impacts for the summer and autumn 2015 Test Periods for the 12 feeders originally included in the project.[94] This report found the following over the two test periods:

- Voltage reduction averaged 1.6%, compared PG&E's forecast of 3% to 3.8%.[95]
- Conservation Voltage Reduction (CVR) factor of 0.8, compared PG&E's forecast of 0.6 to 0.75.[96]

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[92] PG&E response to ORA-19-Q15, Attachment 3, slide 4, emphasis added. As discussed two sections below, the proposed VVO program would start on feeders that promise the highest benefits, so the overall B-C will decline over time.

[93] In discovery, ORA directly asked "whether the feeder [each feeder in the pilot program] was operating with CVR" and rather than providing a direct answer, referred to a prior response. See DR-ORA-185-Q18(a). PG&E's response referred to its response to DR-ORA-185-Q4 which stated "PG&E does not track the number of customers with and without CVR. PG&E operates circuits at the lowest practicable peak load voltage in accordance with Electric Rule 2." Also, a progress report dated June 10, 2015, illustrates VVO as reducing voltages from above its CVR upper voltage limit of 120 volts to within this range. See PG&E's response to DR-ORA-19-Q15, Attachment 2, slide 5.

[94] PG&E's response to DR-ORA-185-Q17, Attachment 1, p.1: "the summer 2015 test period ran from each subject transformer bank's "go-live" date through September 15, 2015. The autumn 2015 test period ran from September 16-November 30, 2015. In the remainder of this document they will be referred to as P1 and P2, respectively."

[95] PG&E's response to DR-ORA-185-Q17, Attachment 1, p.23. PG&E figures are taken from Ex. PG&E-4-WP, WP Table 13-21, lines 1 and 2.

[96] PG&E's response to DR-ORA-185-Q17, Attachment 1, p.23. PG&E figures are taken from Ex. PG&E-4-WP, WP Table 13-21, lines 1 and 2.

The combined impact of these two variables, which define the program benefits, is customer energy savings, which the pilot found to be 1.3%, compared to PG&E's forecast of 1.8% to 2.85%. Qualitatively, these results show that the VVO system performance to date is at the low end of the range that PG&E's forecast for the VVO pilot (1.3% vs. 1% to 2%) and below the range PG&E forecast for the proposed VVO program (1.3% vs. 1.8% to 2.85%).

ORA conducted a scenario analysis where the pilot project energy savings values were used as an input in PG&E's Volt/VAR Optimization benefit- to- cost model, and found a benefit-to-cost ratio of 0.94 to 1.07 overall, using the same 15 and 20 year service lives respectively as PG&E used in its Low Benefit and High Benefit scenarios.[97] While these figures suggest that the proposed VVO program is very close to cost effective, PG&E's model showed that only 35 to 45 feeders had a benefit-to-cost ratio greater than 1.00, rather than 65-290 in PG&E's forecast. If ORA's understanding is correct, the scope of the program should be reduced, and the actual benefit-to-cost ratio will be lower than 0.94 to 1.07 overall once fixed costs are properly allocated to this smaller scoped program.[98] In addition, the biases discussed above would further reduce calculated cost effectiveness once they are factored in.

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[97] See Exhibit ORA-10 Workpapers, part 2.xls. This spreadsheet is an unaltered version of PG&E's cost effectiveness analysis shown in Ex. PG&E-4-WP, WP Table 13-21, and as provided in electronic format in PG&E's response to DR-ORA-185-Q7, Revision 1, Attachment 1. This spreadsheet relies on inputs in in cells E34, E35, E38, and E39 of tab "Calculation Tab" that are obtained from a large and detailed model provided separately in PG&E's response to DR-ORA-19-Q6, Supplement 2, Attachment 1. Tab "Scenarios" of ORA's workpaper part 2 provides the results of ORA running multiple scenarios using PG&E's detailed model. Note that PG&E's model does not provide a direct input for voltage reduction, but instead uses the "LTC Band Center" voltage as a proxy. According to PG&E, an LTC Band center of 122.25 volts corresponds to a 1.6% voltage reduction. See PG&E's response to DR-ORA-Oral-30-Q1.

[98] Ex. PG&E-4-WP, WP Table 13-16 includes VVO costs, but does not classify which are fixed and which depend on the scope of the program in terms of number of feeders included. ORA believes that large portions, if not all, of line 8, 10, 13, 32, and 40 are fixed costs.

PG&E's justification for this program rests on its forecast that it will be cost-effective. This forecast overestimates benefit-to-cost ratios because existing CVR programs are not properly accounted for. Separate from this forecast, preliminary results from the VVO Pilot, which is biased towards circuits likely to show high benefits from VVO, indicate that program benefits are not as high as forecast, and that a wider scale VVO program may not be cost effective. At a minimum, consideration of the reasonableness of this program should be delayed until the final results for the Volt/Var Optimization pilot project have been reported and vetted, and the implications on wide-scale deployment can be determined. However, ORA believes that the current proposal should not be considered until its compatibility with smart inverters can be determined, as discussed in the next section.

d. Smart Inverters

The proposed Volt/ VAR Optimization program fails to take into account emergent technologies that can help stabilize distribution circuit voltages. A goal of the Volt/VAR Optimization Pilot was to "improve voltage control on circuits with high DG penetration,"[99] and to "support increased penetration of DERs."[100] While other technologies such as storage devices will be part of the solution, "smart inverters," as described below, play a unique role because they are funded by Distributed Energy Resource providers and will be deployed in concert with the perceived problem that Volt/VAR Optimization program seeks to mitigate.[101]

Generally in California, about 90% of local (small scale) renewable generation is connected to the distribution grid through inverters.[102] All inverters convert DC

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[99] PG&E's response to ORA-19-Q15, Attachment 2, slide 5.

[100] PG&E's response to ORA 21-Q3, Attachment 1, p.5.

[101] PG&E's response to DR-ORA-21-Q2 indicates that smart inverters and solid state voltage regulators can aid VVO. In addition, ORA understands that batteries can assist with voltage support, both through customer-sited units that are now commercially available (for example, Tesla, Sonnen, Orison, and JLM Energy now offer commercial units), and larger units such as those proposed in response to PG&E's storage RFO application, A-15-12-004.

[102] D. 14-12-035, pp. 2-3.

electricity to AC, and some help optimize power production from solar panels or control battery charging, but "smart inverters" add features that help minimize any adverse grid impacts from DER. In D.14-12-035, the Commission summarized smart inverter capabilities and adopted seven specific features recommended by a smart inverter working group (SIWG).[103] In adopting the first phase of mandatory smart inverter standards the Commission stated:

> The voltage on a distribution line is now controlled by shunt capacitors, voltage regulators on the line, and a voltage regulator in the distribution transformer at the substation controlled by a line drop compensation algorithm. **The smart inverter has the potential to substitute for all of these measures with greater accuracy and at lower cost**.[104]

Phase 1 smart inverter features, which include dynamic Volt-Var Operation, will become mandatory for all new installations 12 months after the date the Underwriters Laboratory (UL) approves the applicable standards.[105] While UL approval is expected in 2016, the Commission also stated that "Smart inverter requirement[s] shall be permitted and encouraged to be used, but not mandated, on all new inverter installations up until the date that these new standards become mandatory."[106] PG&E estimates that it will have approximately 500,000 solar

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[103] D. 14-12-035, pp. 3-4.

[104] D. 14-12-035, p. 14, emphasis added. PG&E acknowledges that smart inverters will include the autonomous "capability to actively counteract voltage changes" per PG&E's response to DR-ORA 21-Q3, Attachment 1, p. 6.

[105] The feature adopted is dynamic Volt/Var Operation, as opposed to Volt/Var Optimization. D. 14-12-035, Finding of Fact 7, p. 18. For PG&E, the technical requirements for this feature are defined in Section Hh.2.j of Rule 21, page 174: "The Smart Inverter shall be capable of operating dynamically within a power factor range of +/- 0.85 PF for larger (>15 kW) systems, down to 20% of rated power, and +/- 0.9 PF for smaller systems (≤15 kW), down to 20% of rated power, based on available reactive power. This dynamic Volt/VAR capability shall be able to be activated or deactivated in accordance with Distribution Provider requirements." Additionally, "The Smart Inverter shall be able to consume reactive power in response to an increase in line voltage, and produce reactive power in response to a decrease in line voltage."

[106] D. 14-12-035, Finding of Fact 7, p. 9. Also, PG&E's response to DR-ORA-22-Q7

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photovoltaic (PV) distributed generation systems connected to the grid by 2025 and that more than 300,000 of these will utilize smart Inverters.[107] Therefore smart inverter features that help minimize the impact of Distributed Energy Resources on the distribution system will be deployed in concert with a majority of the DER generators that are the alleged problem.

PG&E's testimony and work papers make no mention of smart inverters or other technologies as an alternative to Volt/ VAR Optimization. PG&E's 2015 annual Smart Grid report does not mention smart inverters in its discussion of the Volt/ VAR Optimization Pilot.[108] In response to ORA discovery, PG&E provided an internal document that stated PG&E is investigating whether smart inverters and solid-state voltage regulators could "aid VVO," but this document was neither submitted to nor approved by the CPUC.[109] In addition, one of the two phases proposed in the Volt/VAR Optimization Pilot to address smart inverters has been "de-scoped."[110] Smart inverters should be considered before VVO, as the preferred method of stabilizing voltage and supporting Conservation Voltage Reduction, since Phase 1 functions including dynamic Volt-Var operation are already mandated and scheduled for deployment.

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indicates UL approval is "estimated to occur before year end." This response was dated October 19, 2015 and UL approval is expected in 2016.

[107] PG&E's response to ORA 21-Q3, Attachment 1, p. 5.

[108] Annual report in R.08-12-009 dated October 1, 2015, p. 27.

[109] The document is Attachment 1 to PG&E's response to DR-ORA-21-Q3. PG&E's response to DR-ORA-185-Q14e indicates the document was not approved by or sent to the CPUC. Within this response, PG&E incorrectly states that the VVO Pilot has a "Phase 3: Advanced Functionality and Optimization that is discussed in the Attachment to DR-ORA-21-Q3." "Phase 3" is also not mentioned in the 2015 Smart Grid Annual Report in R.08-12-009 dated October 1, 2015; in the Smart Grid Pilot Deployment Projects Implementation Plan that defined the VVO Pilot, AL 4227-E dated May 22, 2013; or in VVO Pilot status reports provided as Attachment 1 to PG&E's response to DR-ORA-185-Q15.

[110] The two phases are described in PG&E's response to DR-ORA 21-Q3, Attachment 1, pp. 13 and 17. PG&E's response to DR-ORA-185-Q16, states that Phase 2, described as "Automated Coordination of Multiple Smart Inverters," was de-scoped.

Phase 1 smart inverter features adopted in D.14-12-035 are autonomous features, so for example dynamic Volt/Var operation automatically adjusts the inverter's ability to absorb reactive power in response to changes in voltage at the inverter, independent of steps PG&E takes to optimize voltages on the circuit. Therefore at a minimum, PG&E must demonstrate that the proposed Volt/Var Optimization program reduces voltage as promised even on feeders where smart inverters are autonomously performing a similar function.

e. Communication with Smart Inverters

Implementation of PG&E's Volt/ VAR Optimization plan requires both upgrades to existing SCADA network and a new Field Area Network [FAN].[111] Proposed smart inverter functions, beyond those mandated by D.14-12-035, will require communications between the inverter and the utility.[112] Nothing in PG&E's testimony on the proposed Field Area Network, nor in the entire chapter on IT, make mention of smart inverters.[113] ORA asked if PG&E's proposed Field Area Network could accommodate smart inverter functionality, and for documentation of this

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[111] PG&E's response to DR-ORA-20 Q2, Q3, and Q20. The new FAN, described in Ex. PG&E- 7, pp. WP 9-184 to WP 9-189, is proposed to serve multiple uses, not just VVO. The cost for this GRC period is $26.9 million and "the duration of the FAN program will extend beyond the 2017 GRC period and PG&E will request additional funding for this project in subsequent years," Ex. PG&E- 7-WP, p. 9-187.

[112] Administrative Law Judge (ALJ) ruling dated February 7, 2014 in R.11-09-011 included Attachment 1 which provided the initial recommendations of the Smart Inverter Working group. This included specific recommendations for Phase 1 autonomous functions, and proposed definitions for Phase 2 to focus on "communication capabilities and standards for inverters" and Phase 3 to "define and propose an implementation plan for establishing a set of advanced inverter functionalities that benefit from the communications capabilities developed in Proposed Phase 2." See pages 15-16. SIWG provided final Phase 2 recommendations in a February 28, 2015 document, and Phase 3 recommendations in a April 2, 2016 document. See http://www.energy.ca.gov/electricity_analysis/rule21/. During the March 17, 2016 CPUC commission meeting, the commissioners discussed how to move the Phase 2 and Phase 3 documents into the record of R.11-09-011. ORA understands that this will be a topic in an all-Party meeting scheduled for April 19, 2016.

[113] Ex. PG&E-7, Chapter 9.

fact.[114] PG&E's response was ambiguous in stating that "communicating with Smart Inverters will not use a one-size-fits-all approach, and alternative communications approaches (other than FAN) may be used to communicate with Smart Inverters" but no documents were provided to demonstrate that the FAN would accommodate SIWG Phase 2 and Phase 3 functions.[115]

ORA understands Phase 2 smart inverter protocols have not been adopted by the CPUC, so communication with smart inverters may not have been fully considered in the planning of the Field Area Network. This, in turn, could mean that the new Field Area Network may not be fully compatible with the Smart Inverter Working Group requirements for advanced smart inverter functions, once they are adopted by the CPUC and included in a revised version of Rule 21.

PG&E's track record with its SmartMeter program should be borne in mind when the Commission considers making ratepayers pay for new PG&E communication systems that PG&E has not shown to be capable of supporting CPUC- mandated and pending smart inverter functions. In PG&E's SmartMeter program, PG&E partially deployed two communication systems, and then replaced them at ratepayer expense after systems with superior capabilities were adopted by SCE and SDG&E.[116]

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[114] DR-ORA-188-Q1.

[115] PG&E's response to DR-ORA-188-Q1 provides no supporting documents as attachments. PG&E's response refers to its responses to DR-ORA-20 Q2 and Q20, but these similarly provide no attachments or other support.

[116] D.06-07-027 adopted PG&E's original advanced metering infrastructure (AMI) application A.05-06-028 which used a "Powerline Carrier" (PLC) network from DCSI for electric meters. PG&E refers to its AMI system as the "SmartMeter" system. PG&E began deploying the DCSI-PLC AMI network while simultaneously applying via A.09-03-026 for a meter upgrade to provide features adopted for SCE and SDG&E's AMI systems. Slide 8 of PG&E's June 2008 SmartMeter Program Update report (see attachment 2 to this exhibit) shows that PG&E installed meters using the DCSI-PLC system, then a Hexagram network, before finally transitioning to the Silver Spring Network (SSN) system it ultimately deployed. These details are discussed in D.09-03-026, which approved the SmartMeter Upgrade, pp. 19-22 and 50-56. Ratepayers funded these replacements as part of the risk-based allowances approved by the Commission: $128.8 million for the original application and $47 million ($65.5 million less $18.5 million disallowed) for the upgrade. See D.09-03-026, pp.

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The experience with PG&E's SmartMeters underscores the need for caution when the Commission considers assigning the cost of this project to PG&E's ratepayers. ORA recommends that if the Commission grants PG&E's request, and the communication systems prove incompatible with smart inverters, then PG&E shareholders should bear the replacement burden.

f. PG&E's Volt/ VAR Optimization Cost Estimates

As discussed above, ORA recommends that PG&E's request for a new VVO program be denied for this GRC cycle. However, the Commission may choose to authorize deployment of Volt/Var Optimization systems because it believes PG&E made a compelling showing that: (a) a version of the program is cost-effective based on the final results of the Volt/Var Optimization pilot project; and (b) its communication networks and VVO systems are compatible with Phase 2 and 3 smart inverter requirements. If so, ORA recommends adjustments to PG&E's proposed expenditures.

Ex. PG&E-4-WP, Table 13-16 shows how cost components aggregate into the annual forecast for the Volt/ VAR Optimization program. One of these cost elements, "electric system modifications," is further detailed in Ex. PG&E-4-WP, Table 13-19, which calculates unit costs per feeder. The unit cost is then multiplied by the forecasted units per year to get annual costs. While PG&E has indicated that it only needs to install communicating controllers on existing voltage control devices, the cost estimates include replacing some of the actual capacitor banks and voltage regulators.[117] Removing these costs reduces the unit cost for distribution

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87-93.

[117] PG&E's response to DR-ORA-21-Q5 stated "These controllers are separate, but attached to the actual equipment hardware (e.g., capacitor banks, regulators, and load tap changers (LTCs)), thus only the controller itself will need to be upgraded, rather than the entire piece of hardware." PG&E's response to DR-ORA-21-Q14 stated "The existing line regulator or capacitor bank can be left in place, and only the controller replaced." However, the cost for each of these is included in the unit cost calculations in Ex. PG&E-4-WP, WP Table 13-19 at lines 3 and 4, and the inclusion of these costs in WP Table 13-15 at lines 17 and 19 confirm that these are the costs for new capacitors and regulators, and these are the costs used to determine the costs for other capacity projects requested in Ex. PG&E-4,

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equipment from $91,800 per feeder to $45,000 per feeder. Given that PG&E has forecast only 18 feeders will be modified in 2017, the impact in that year is less than $1 million, but for the 210 units forecast for 2018 and 2019 the impact is over $9.8 million.[118]

In addition, PG&E's workpapers include the costs of providing SCADA communication and control equipment totaling $113.330 per feeder for a projected 2017 cost of $2.040 million for 18 feeders as part of the requested funding[119] However PG&E indicates that it is "prioritizing VVO deployment to SCADA enabled substations and feeders to reduce VVO implementation costs and complexity."[120] If this is the situation, then SCADA communication costs should not be included and the 2017 requisition should be reduced by $2.040 million.

The cost impact of these two cost adjustments is based on PG&E's proposed scope and deployment schedule. If the Commission adopts a modified (i.e. scaled back or delayed initiation) version of the Volt/VAR Optimization program, the cost impact will likely change based on the adopted scope and schedule.

C. Recommendations Regarding Distribution Resource Plan Related Expenditures

Chapter 13 of Ex. PG&E-4 illustrates PG&E's asymmetrical response to AB 327 and the Distribution Resource Plan proceeding. In this GRC, PG&E requests approval for new expenditures for the DERIC and Volt/ VAR programs, but provides no evidence that it is reducing any expenditures due to Distributed Energy

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Chapter 13. ORA also notes that line 6 of WP Table 13-19 is for a "line voltage regulator controller upgrade" which is clearly different from the "line voltage regulator" in line 4. PG&E's response to DR-ORA-185-Q13 confirms this situation.

[118] Ex. PG&E-4-WP, WP Table 13-19, footnote 4, line 42. 210 units multiplied by a reduction of $46,800 per unit ($91,800 - $45,000) is $9.828 million.

[119] Ex. PG&E-4-WP, WP Table 13-19, sum of lines 6, 17, and 23.

[120] PG&E's response to DR-ORA-185-Q10.

Resources.[121] PG&E does not demonstrate its Distributed Resource Plan- related investment is cost-effective.[122] So, while the Legislature and the CPUC view the DRP process as a means to integrate Distributed Energy Resources and decrease distribution system costs, PG&E instead is utilizing the DRP process to increase distribution costs.

To be consistent with the intent of AB 327 and California policy generally, ORA recommends that PG&E's request to augment investments through the DERIC VVO programs be rejected. To ensure that PG&E's next GRC filing is based on a correct interpretation of AB 327, as implemented by the CPUC in the DRP proceeding, ORA recommends that:

- DRP related expenditures should be consistent with the AB 327 and should not prejudge findings and orders in the DRP proceeding,
- Requests for ratepayer funding of proposed programs, such as the Distributed Energy Resources Integration Capacity program, must account for payments per Rule 21 or WDT from DER providers,
- Programs intended to integrate DER should be fully compatible with smart inverter functionality, both those adopted and those likely to be adopted,
- The Commission should investigate why PG&E is not currently required to implement CVR, and whether this condition is justified given the state's current policy goals,
- The Commission should investigate if PG&E has received funding for CVR in the past, and if it should already be implementing CVR without further ratepayer investments,
- Cost effectiveness analyses should use the appropriate CPUC approved tests and input data,
- Alternatives conservation voltage reduction methods, including those used by SCE and SDG&E, need to be considered as alternatives to VVO,

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[121] Ex. PG&E-4, Chapter 15 also includes DER related requests for distribution technology investments, but no deductions or delays in expenditures based on DER deployment.

[122] PG&E's response to ORA-22-Q15 regarding DERIC. See also Ex. 4, p. 13-7: "Therefore, DER alternatives may only be cost effective for a subset of the projects analyzed."

- Results from the VVO pilot program must be vetted and considered within the context of PG&E's entire distribution system before a wide-scale VVO program can be considered,
- If the Commission approves a version of the VVO program in the future, ORA proposed cost adjustments should be incorporated.

Two of these recommendations have not been discussed previously in this testimony. First, the Commission has extensive experience with cost-effectiveness evaluation of demand side programs like energy efficiency and demand response and developed the Standard Practice Manual (SPM) for this purpose.[123] In addition, the scope of the active Integrated Distributed Energy Resources (IDER) proceeding R.14-10-003 includes developing technology neutral cost-effectiveness methods to be used across "resource-specific" proceedings.[124] ORA recommends that the methods developed in R.14-10-003 be used for comparing traditional grid improvements and DER alternatives in GRC proceedings. SPM tests and cost-effectiveness protocols and data developed and adopted in other demand-side proceedings could be used on an interim basis until R.14-10-003 is concluded.

Second, PG&E and all utilities should be required to report each instance where DER is evaluated as an alternative to traditional investments. ORA proposes this reporting requirement going beyond that required by D.14-01-046, referenced in Section IV.B.2, by requiring that evaluations be reported whether they result in a deferral or not. Without this information, the CPUC and parties will have no data to support whether and to what extent PG&E is adequately evaluating DER in their distribution planning process.

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[123] California Standard Practice Manual Economic Analysis of Demand-Side Programs and Projects, October 2001. Available at http://www.cpuc.ca.gov/egyefficiency/.

[124] Assigned Administrative Law Judge Ruling in R.14-10-003 dated February 26, 2016, p.7: "Continued development of technology-neutral cost-effectiveness methods and protocols, including but not limited to: a. Refinement and enhancement of valuation or cost effectiveness methods, including locational variation, established in this proceeding for the consistent use in resource-specific proceedings."

V. ELECTRIC DISTRIBUTION WORK REQESTED BY OTHERS – RULE 20A

Under the Rule 20A Program, PG&E converts existing overhead electric distribution facilities to underground. In order for a project to qualify for the Rule 20A Program, the project must meet specific criteria outlined in the Rule 20A tariff.[125] Rule 20 was established in 1967 with significant modifications in 1990, 2002, and 2011.[126]

A. Overview of PG&E's and ORA's Forecasts

The following Table 10-5 summarizes historic expenditures, PG&E's request, and ORA's recommendation for MWC 30, Electric Distribution WRO – Rule 20A capital expenditures.

[125] Ex. PG&E-4, p. 18-3.

[126] PG&E's response to DR-ORA-36-Q3.

Table 10-5
Electric Distribution Capital Expenditures
MWC 30 - Rule 20A Undergrounding Program
(In Thousands of Dollars)

			1	2	3	4	5	6	7	8	9	10	11
			Recorded[1]							Estimated[2]			
Line #	MWC	MWC Description	2010	2011	2012	2013	2014	2015 [3]		2016		2017	
								PG&E	ORA	PG&E	ORA	PG&E	ORA
1	30	WRO Rule 20A	$36,610	$33,628	$52,426	$69,378	$41,116	$76,000	$41,885	$78,000	$47,687	$79,000	$47,687
2	30	Escalation	–	--	--	--	--	--	--	$2,184	$0	$4,740	$1,526
3	30	Total	$36,610	$33,628	$52,426	$69,378	$41,116	$76,000	$41,885	$80,184	$47,687	$83,740	$49,213

Notes:

[1] Recorded data for 2010-2014 from PG&E WP Table 18-1. 2014 value includes $24.4 million of shareholder funded expenditures, per footnote.

[2] PG&E estimated data from PG&E WP Table 18-6.

[3] For 2015, ORA's forecast uses 2015 recorded costs from PG&E's response to DR-ORA-Oral-25.

B. Background on Rule 20A Work Credits

Rule 20A project funding has two distinct but related terms: "work credits" and "expenditures." Expenditures are the funds actually authorized, budgeted, and expended each year that result in overhead lines being relocated underground. Expenditures in the context of the Rule 20A program are the same as for any other program.[127] "Work Credits" on the other hand are unique to this program which PG&E compares to frequent-flyer miles: they have no inherent monetary value, but can be traded for real benefits (i.e., conversion of overhead lines) without expenditure by the municipality.[128] Work credits provide for the following in the Rule 20A program:

1. Annual funding targets for PG&E's service territory as a whole;
2. Tracking PG&E's ability to perform conversions relative to the annual targets;
3. Set annual funding allocations for individual municipalities within PG&E's service territory; and
4. Authorizing specific conversion projects at a municipality.

ORA views the work credit allocation as the authorized annual scope of work for PG&E's Rule 20A program since work credits are converted on a one-to-one basis for project authorization and funding. The following Figure 10-1 shows the annual work credit allocation for PG&E since 1989:[129]

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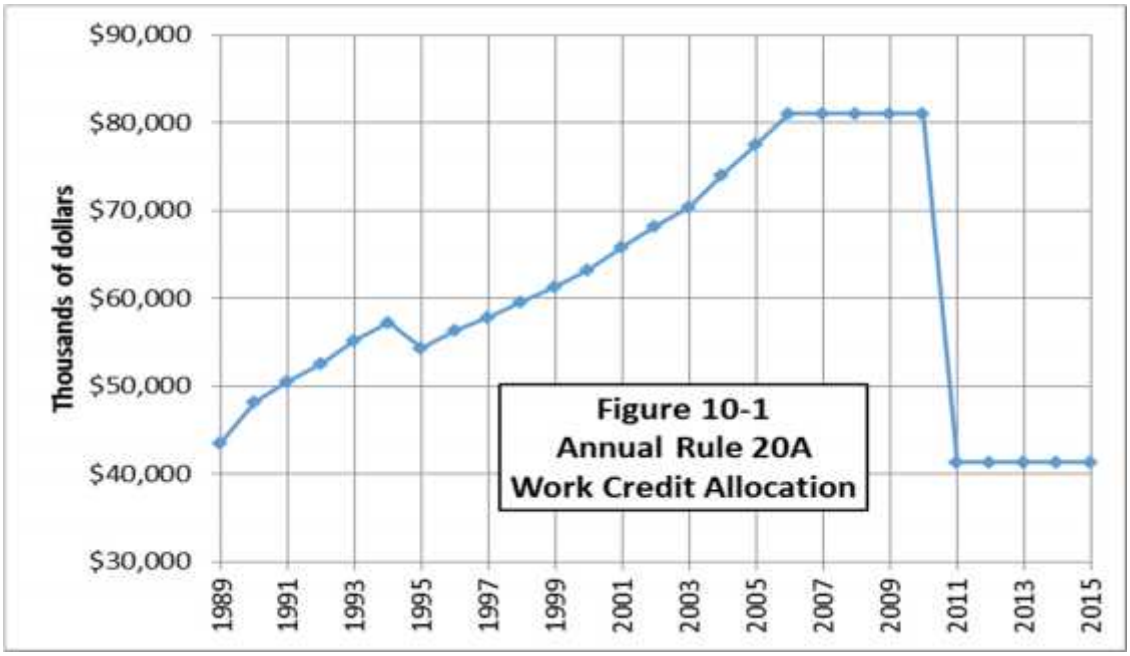
[127] The way Rule 20A project funding usually works is as follows: PG&E forecasts expenditures, parties critique these forecasts and offer alternatives, the CPUC authorizes funding, PG&E establishes budgets consistent with the authorized funding, and actual expenditures for work performed are recorded in PG&E's SAP accounting system.

[128] Ex. PG&E-4 from the 2014 GRC, A.12-11-009 at page 18-6 states the work credits "are analogous to the accumulation of "frequent flyer miles." Once a community has accumulated enough "miles" and is ready to proceed with a specific project, the "miles" are "redeemed" toward the cost of the ratepayer funded conversion and the project is added to the Rule 20A Project queue to wait for actual funding."

[129] PG&E's response to DR-ORA-104-Q10, Revision 1, Attachment 1. Data formatted by ORA.



This chart shows that the scope of the program was cut roughly in half in 2011 in response to a growing accumulation of work credits that exceeded nine years of annual allocation in 2010.[130] In adopting this reduction the CPUC stated:

> Pacific Gas and Electric Company shall allocate work credits at the same level and in the same amount as Pacific Gas and Electric Company's Rule 20A annual budgeted project amount for 2010, in order to stop the escalation of work credit allocations. Communities with projects already in progress shall be allowed to continue with their projects, even if they exceed the 5-year allowable borrowing period under the modified Rule 20A allocation method adopted herein.[131]

This reduction resulted in drawdown of the balance, but then stabilization at approximately $540 million from 2011- 2015, as shown in Figure 10-2 below.[132]

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[130] 2010 work credit balance was $743.4 million, or 9.2 times the annual allocation of $81.0 million. See PG&E's response to DR-ORA-104-Q10, Revision 1, Attachment 1.

[131] D.11-05-018, OP 6, p. 90.

[132] PG&E's response to DR-ORA-104-Q10, Revision 1, Attachment 1. Numeric data prior to 2006 was not provided and PG&E noted "Comprehensive "snapshot" reporting of work

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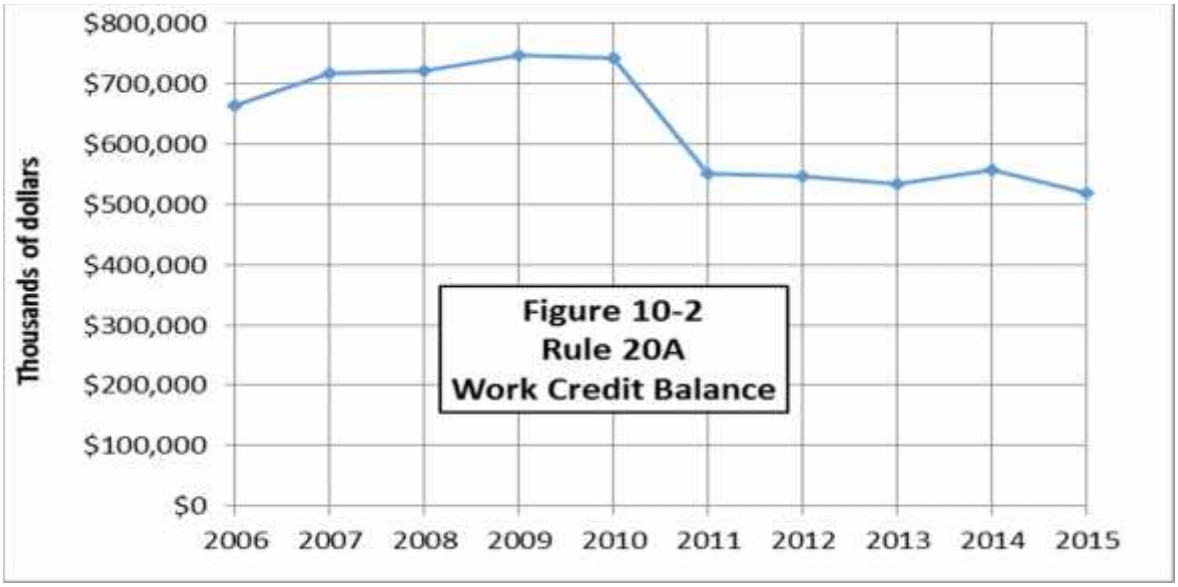
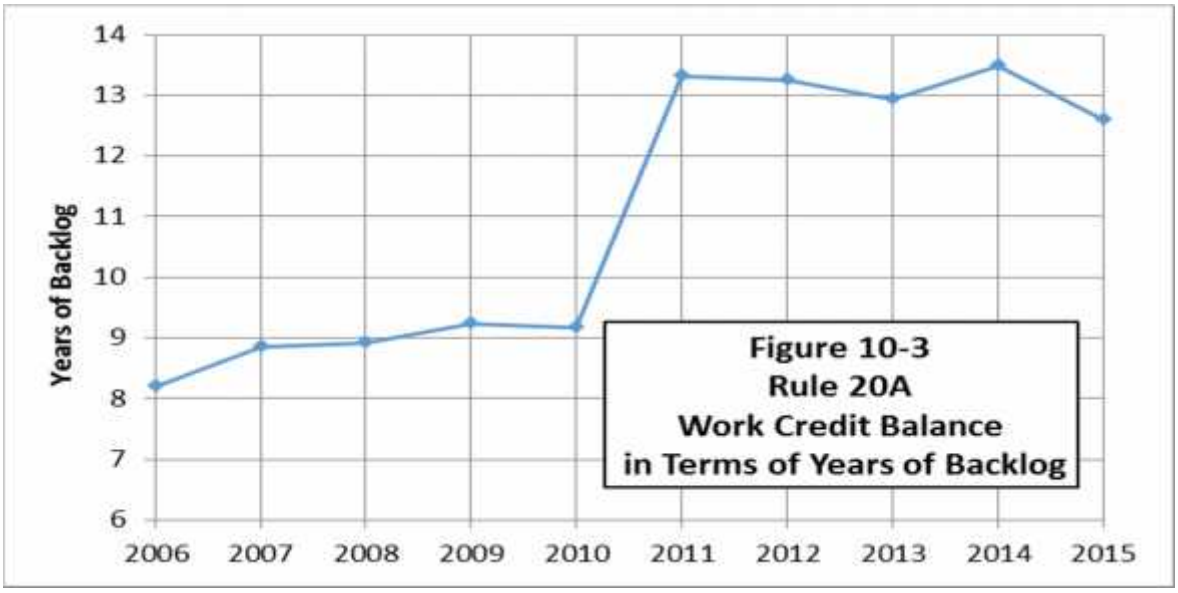


Figure 10-3 shows the work credit balance in terms of the number of years of backlog, based on the adopted annual work credit allocation.[133]



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credit balances did not begin until 2006." PG&E's response to DR-ORA-206-Q9 confirmed that all data provided in Attachment 1 to PG&E's response to DR-ORA-104-Q10 is collected and presented consistently such that it accurately reflects trends in data.

[133] PG&E's response to DR-ORA-104-Q10, Revision 1, Attachment 1. Data formatted by ORA.

This chart illustrates that the reduction of the annual work credit allocation to $41.3 million per year was followed by a one-time reduction in the work credit backlog in terms of dollars, but also a one-time increase in the backlog in terms of years. The back log of work credits is currently at more than 12 times the annual allocation.

One feature of the Rule 20A program is that it allows municipalities to "borrow" up to five years of annual work credits when projects are authorized. For example, if the City of Oakland has an annual work credit allocation of $1.0 million and wants to initiate a $10 million conversion project, it only needs to save work credits for five years before PG&E will proceed with the project.[134] The work credit balances in Figures 10-2 and 10-3 above include the five year borrow amount, but exclude work credits allocated to defined or "committed" projects.[135]

C. ORA's Analysis

Table 10-5 above shows that PG&E's forecast for Rule 20A conversions expenditures exceed all previously recorded expenditures. Coupled with a request to continue the current $41.3 million annual work credit allocation, PG&E claims "this will allow PG&E to continue to reduce accumulated work credit balances and achieve a "steady state" in which PG&E can focus exclusively on timely completion of new projects."[136] This is similar to the justification for PG&E's request in its 2014 GRC for approximately $88 million per year.[137]

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[134] In this case Oakland would have a work credit balance of $10 million including $5 million of accrued credits and $5 million of borrowed credits.

[135] PG&E's response to DR-ORA-206-Q9 confirmed that Work Credit Balances for each year in Attachment 1 to PG&E's response to DR-ORA-104-Q10 includes the five-year borrow amount. Also see PG&E's response to DR-ORA-207-Q12.

[136] Ex. PG&E -4, p. 18-1.

[137] In its 2014 GRC testimony, PG&E said that: PG&E also requests that the Commission extend through 2016 the annual work credit allocation amount of $41.3 million adopted in the 2011 General Rate Case (GRC) decision, **which will allow PG&E to reduce the backlog of approved Rule 20A work that accrued under the previous work credit allocation method**." PG&E 2014 GRC, A.12-11-009, Ex. PG&E -4, p. 18-1, emphasis

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In the 2014 GRC, the Commission concluded that "PG&E has repeatedly presented forecasts in prior GRCs with the intention of reducing the backlog in Rule 20A projects, but has also repeatedly spent less than the forecast." The Commission then approved continuation of the $41.3 million annual work credit allocation and ORA's forecast of $52.426 million for 2012-2014.[138]

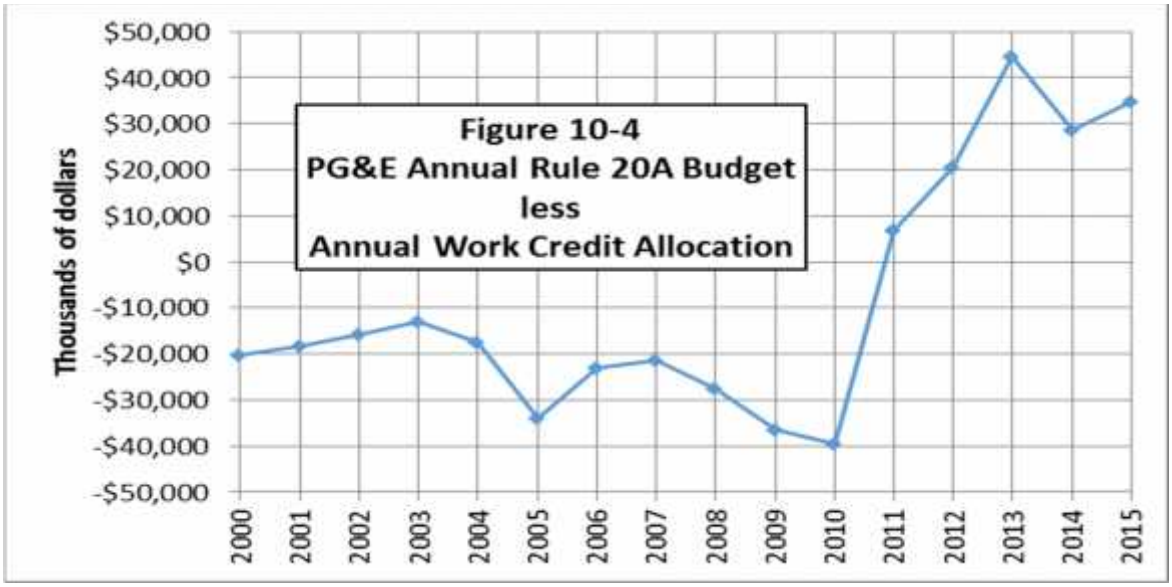
ORA has attempted to determine why PG&E has not succeeded in reducing the backlog of work credits. It appears that PG&E establishes its internal budget for Rule 20A program not on the GRC forecast amounts, but on project level forecasts from the year before.[139] ORA compared PG&E's internal budget to the annual work credit allocation, which ORA uses as a proxy for the authorized annual scope of the program.[140] Figure 10-4 below shows that, until 2010, PG&E consistently set its internal budgets lower than the annual work credit allocation, and that it was not planning to reduce the backlog.

(continued from previous page)
added. In that proceeding, PG&E forecast $88.5, $88.2, $88.1, and $88.4 million for 2014 to 2016 respectively.

[138] D.14-08-032, p. 251, and Ex. DRA-7 in A.12-11-009, p. 66. ORA was the Division of Ratepayer Advocates (DRA) during the 2014 GRC.

[139] PG&E's response to DR-ORA-104-Q8. In fact, PG&E's internal budgets for this program were $77.4 million higher than CPUC authorized capital expenditures. See PG&E's response to DR-ORA-206-Q6.

[140] ORA used the annual work credit allocation as a proxy for the program scope. The CPUC authorized funding per year could be used as an alternative metric, but the 2011 GRC was resolved through a settlement process which did not provide explicit funding authorization for this MWC. See D. 11.05-018. PG&E internal budgets and work credit allocations are taken from Attachment 1 to PG&E response to DR-ORA-104-Q10, revision 1.



However, starting in 2011, PG&E began to set budgets higher than the annual allocation, which was reduced to $41.3 million annually as shown in Figure 10-1. The combination of higher budgets and lower annual allocations did reduce the backlog, but not on a continuing basis. From 2000 through 2015, PG&E budgets for Rule 20A work totaled $130.9 million less that the work credits allocated during the same time period.[141] This shows the extent to which PG&E planning did not attempt to meet the adopted program scope.

One reason the backlog has not been reduced is that PG&E has not been able to perform work consistent with its budgets. As shown in Figure 10-5 below, PG&E has met or exceeded its program budget in only four years since the year 2000, none which corresponded to the higher budgets of the 2012-15 period.

[141] See Exhibit ORA-10 Workpaper, part 3.xls for calculation.

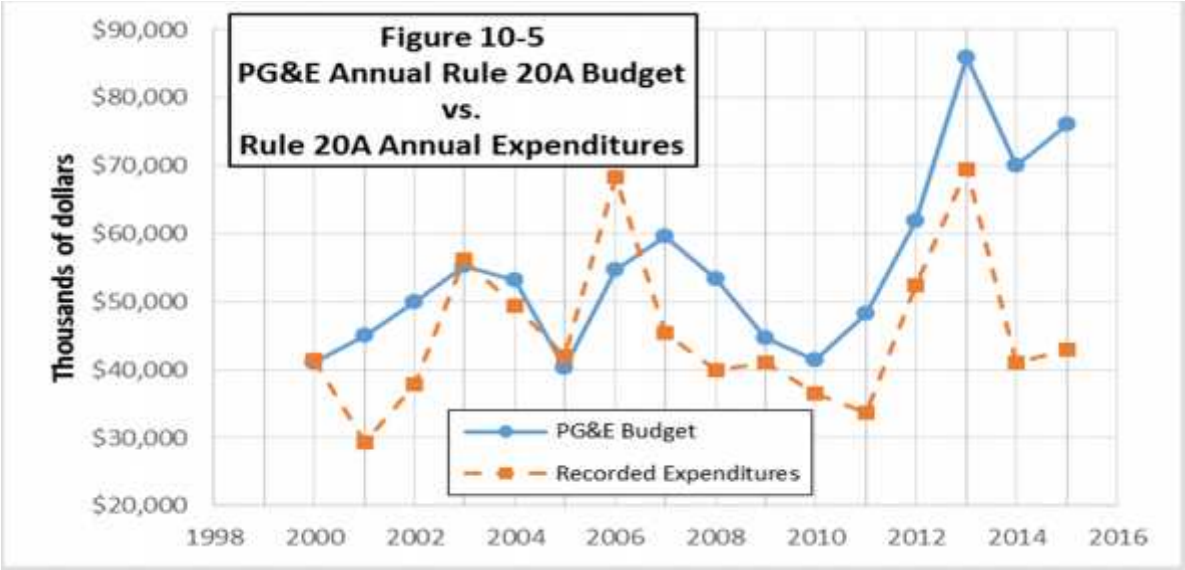


Figure 10-5 shows that PG&E has spent less than its budget every year since 2006. Cumulatively, PG&E has spent $153.5 million less than its budgets since 2000.[142] Combining the impacts of budgeting and implementation shortfalls since 2000, PG&E has spent $284.5 million less than the planned program scope based on work credit allocations.

Finally, while PG&E's recorded expenditures for the program have peaked at nearly $70 million per year twice in the past, in 2006 and 2013, expenditures have declined in real terms, as shown in Figure 10-6.[143]

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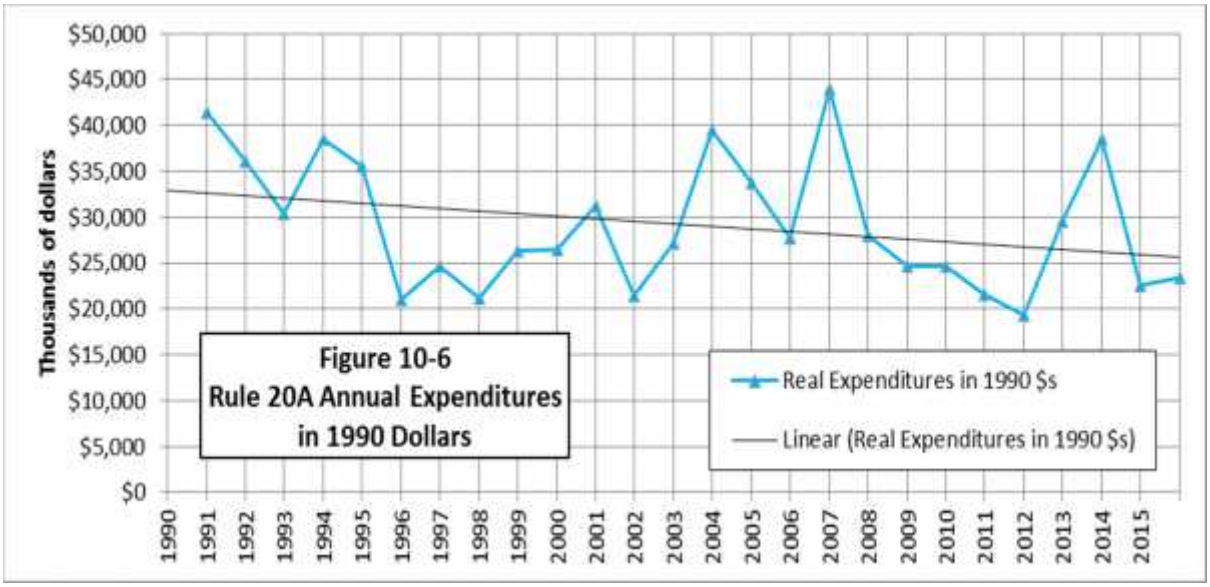
[142] See Exhibit ORA-10 Workpaper, part 3.xls for calculation.

[143] Recorded expenditures deflated using the annual Consumer Price Index for urban consumer (CPI-U). See Exhibit ORA-10 Workpaper, part 3.xls.



Thus, historically, PG&E has been unable to maintain the scope of Rule 20A conversations in terms of work performed (i.e., miles of cable or number of customers converted), assuming PG&E's costs have tracked inflation.[144] In addition, the backlog of work credits has stagnated at over $500 million, or more than 12 times the annual allocation.

PG&E has not demonstrated how it will increase its ability to complete Rule 20A conversions and meet its stated objective of reducing the work credit backlog. PG&E testimony does not express the extent or duration of the backlog problem, barriers that have prevented increasing the pace of work, or provide any specific plans for how it will reduce the backlog. For example, PG&E describes the management structure of the program, but makes no mention of whether additional staff are needed or requested.[145] ORA confirmed that PG&E is not increasing program staff for the pending GRC period.[146] Given that PG&E is not requesting

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[144] While spending has been relatively consistent over this time period, inflation has eroded the power of these expenditures and resulted in less work actually performed.

[145] Ex. PG&E-4, p. 18-4.

[146] PG&E's response to DR-ORA-104-Q4.

additional staff or other resources for this program, it is unlikely that PG&E will double its work capacity to support its requested funding levels for 2016-2017.

Moreover, PG&E's application included a forecast for 2015 expenditures of $76.0 million, but recorded only $41.9 million, or 55% of this forecast amount.[147] This shortfall is striking in that the 2015 forecast was based exclusively on "identified work" that was in the planning stage or beyond, while the forecast for 2017 relies on over $25 million of forecasted projects, or those in the pre-planning stage.[148] The magnitude of the 2015 shortfall, and its timing relative to the GRC request, demonstrate that PG&E will not meet its 2016 and 2017 forecasts.

Per PG&E testimony and workpapers, PG&E recorded $24.4 million in expenditures for projects that had insufficient work credits in 2014.[149] While PG&E admitted that this was an error and accepted that the work would be funded by PG&E shareholders, the result was that only $16.7 million of work credits were consumed and removed from the work credit balance.[150] PG&E now proposes a new process to avoid the problem of performing projects with insufficient work credits going forward, but the process is untested and PG&E's ability to effectively manage the Rule 20A program, even at historic expenditure levels, remains in question.[151]

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[147] PG&E's forecast from Ex. PG&E-4, p. 18-5, recorded cost from PG&E's response to DR-ORA-Oral-25.

[148] PG&E workpapers describe three types of work in Ex. PG&E-4-WP, WP Table 18-7: identified work, additional identified work, and forecast other work. The first type of work is shown in lines 3-20 of WP Table 18-6, and the other two are shown in lines 22 and 25 respectively of the same table.

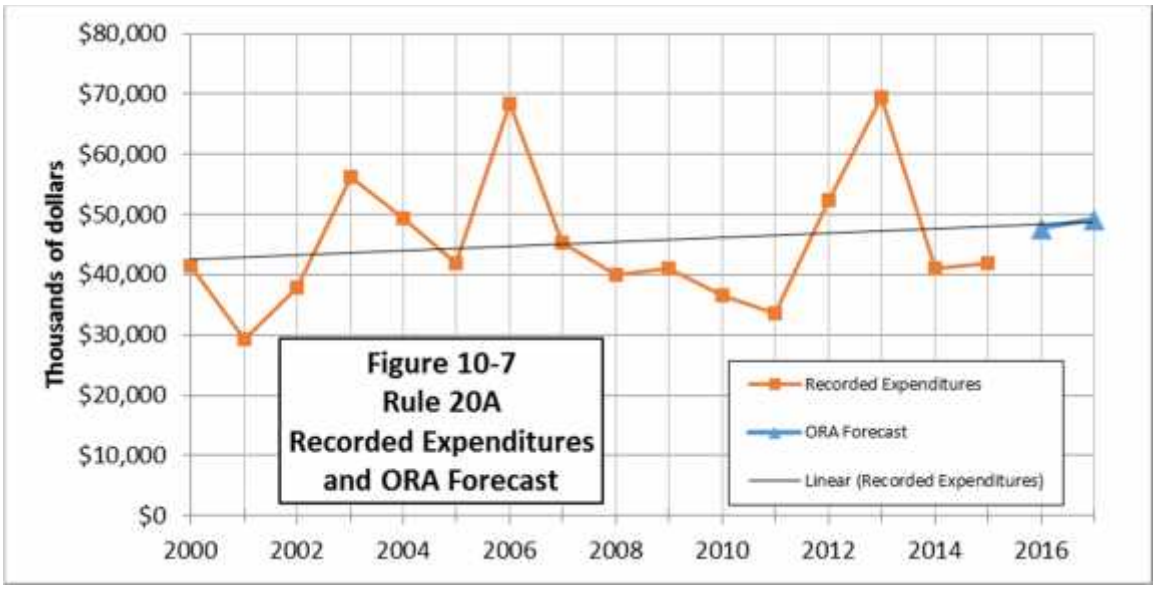
[149] Ex. PG&E-4-WP, p. 18-5; WP Table 18-1, footnote; and WP Table 18-6, line 32.

[150] Ex. PG&E-4-WP, WP Table 18-1, line 1 and pp WP 18-50 to 18-53.

[151] Ex. PG&E-4, p. 18-5. See also PG&E's responses to DR-ORA-36-Q9 and Q10.

D. Summary of Recommendations for Rule 20A Undergrounding Projects

PG&E has not demonstrated it will be able to perform the requested Rule 20A work or shrink the work credit backlog. ORA therefore recommends funding for 2016 of $47,687 million, the average of the last five years of recorded costs, 2011-2015 inclusive. This time period includes the spike in spending in for 2013, and is consistent with the trend of recorded expenditures from 2000 to 2014.



ORA's forecast for 2017 of $49.213 million adds PG&E's proposed escalation rate of 3.2% to the 2016 value.

The Assigned Commissioner Scoping Ruling asked parties to comment whether to extend the $41.3 annual allocation or not.[152] PG&E requests keeping this allocation based on the assumption that PG&E's forecasted expenditures would be realized and would result in a reduction in the backlog.[153] ORA's forecast provides a more reasonable level of expenditures, but would only provide a minimal reduction in the backlog if the allocation is held constant at $41.3 million per year.

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[152] Assigned Commissioner Scoping Ruling dated December 1, 2015, Appendix B, p. 1.

[153] Ex. PG&E-4, p. 18-1.

ORA therefore recommends reducing the allocation to zero for 2017-2019. If PG&E is able to perform conversions at ORA's forecast level, the work credit backlog would be reduced by approximately $150 million, or nearly 30% of the current $520 million backlog.

In the next GRC, annual allocations could potentially be re-instated if PG&E can demonstrate: (1) that it was able to increase spending in 2017-2019 by performing more conversions; and (2) that it has a plan to perform even more conversion in the 2020-2022 time frame.

VI. ELECTRIC WORK REQUESTED BY OTHERS

MWC 10 covers work requested by others (WRO) capital expenditures for: (a) relocating electric distribution and service facilities at the request of a governmental agency or other third parties (e.g., private parties and developers); and (b) overhead electric facility underground conversions covered by Tariff Rules 20B and 20C.[154] For example, a road widening project that required relocation of street lights, distribution poles, or other distribution assets are included in MWC 10.

Unlike Rule 20A projects discussed above, WRO expenditures can be a shared cost with the customer requesting the work. The degree to which costs are shared for a given project is driven by tariff (Electric Rules 15 and 16), the party requesting the work, the location of the existing facilities, and the land rights applicable to those facilities.[155] PG&E asserts that "in all calculations and forecasts PG&E is representing the net cost to PG&E after all customer contributions, or reimbursements, have been applied."[156]

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[154] Ex. PG&E-4, p. 17-14.

[155] Ex. PG&E-4, p. 17-14.

[156] Ex. PG&E-4, p. 17-14.

A. Overview of PG&E's and ORA's Forecasts

PG&E forecasts $98.0 million compared to ORA's forecast of $93.335 million for 2015 capital expenditures.

B. ORA's Analysis

ORA recommends that 2015 recorded costs of $93.335 million be adopted in contrast to PG&E's 2015 forecast of $98.0 million. ORA proposes no adjustments to PG&E's 2016 and 2017 forecast for MWC 10.

VII. ELECTRIC NEW BUSINESS

PG&E states that MWC 16 is for electric new business, which "consists of installing electric infrastructure required to connect new customers to PG&E's distribution system, and to accommodate increased load from existing customers."[157] In actuality, MWC 16 includes only a portion of the expenditures required to serve new customers and new load from existing customers since the new load can lead to capacity upgrades to distribution lines (MWC 6) and substations (MWC 46). MWC 16 also includes expenditures for line transformers used by all electric distribution programs, not just the new business program.[158]

A. Overview of PG&E's and ORA's Forecasts

The following table 10-6 summarizes historic expenditures, PG&E's request, and ORA's recommendation for MWC 16, electric new business capital expenditures.

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[157] Ex. PG&E-4, pp. 17-10 and 17-11.

[158] This includes new transformer purchases and scrapping and disposal costs for old transformers.

Table 10-6
Electric Distribution Capital Expenditures
MWC 16 - New Business Programs
(In Thousands of Dollars)

Line #	MWC	MWC Description	1	2	3	4	5	6	7	8	9	10	11
			Recorded[1]							Estimated[2]			
			2010	2011	2012	2013	2014	2015 [3]		2016		2017	
								PG&E	ORA	PG&E	ORA	PG&E	ORA
1	16	Residential Expenditures	$48,488	$55,330	$56,545	$66,641	$83,328	$89,441	$96,274	$101,151	$101,151	$100,860	$100,860
2	16	Non-Residential Expenditures	$81,626	$100,743	$111,644	$111,656	$138,247	$174,793	$145,463	$183,599	$183,599	$187,323	$187,323
3	16	PEV Related Expenditures	$ -	$1,190	$3,469	$4,159	$5,342	$9,349	$4,408	$11,140	$6,001	$14,552	$6,584
4	16	Transformer Purchases	$47,628	$51,521	$60,139	$66,055	$88,858	$86,764	$100,472	$96,716	$85,110	$101,134	$88,998
5	16	Transformer Scrapping	$3,207	$2,881	$3,731	$4,184	$5,032	$5,252		$5,570	$5,570	$5,896	$5,896
6	16	Other	($13)	$2	($1)	($1)	$10	$ -	$8,827	$ -	$ -	$ -	$ -
7	16	2015 Adjustment						($10,599)	$0				
8	16	Escalation								$11,149	$10,680	$24,586	$23,380
9	16	Total	$180,936	$210,477	$232,058	$248,535	$320,817	$355,000	$355,443	$409,325	$392,111	$434,351	$413,041

Notes:
[1] Recorded data for 2010-2014 from PG&E WP Table 17-27.
[2] PG&E estimated data from PG&E WP Table 17-27.
[3] For 2015, ORA's forecast uses 2015 recorded costs from PG&E's response to DR-ORA-Oral-25.

B. ORA's Analysis

1. Residential Expenditures

Expenditures for line extensions and new service equipment for new residential customers is categorized by MAT codes in lines 2-11 in Table 17-5.[159] Residential customers include new single-family developments, new multi-family buildings, and existing dwellings with new loads other than plug-in electric vehicles (PEV).[160] While the total cost of installing new electric infrastructure is shared between PG&E and the customer requesting the service, as detailed in PG&E's service tariffs (Electric Rules 2, 15, and 16), PG&E's recorded and forecast expenditures are provided net of all customer contributions.[161]

Expenditures for residential connections are shown in line 1 of Table 10-6. ORA uses recorded 2015 expenditures of $96.274 million, which are $6.8 million higher than PG&E's forecast.[162] ORA is not recommending adjustments to PG&E's 2016 or 2017 forecast values.

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[159] Ex. PG&E-4, p. 17-11. MAT 16Z, line 20 of Table 17-5, includes projects where electric service and/or transformer upgrades are required due to added load by an existing customer where no changes are being made to the service panel, per PG&E response to DR-ORA-178-Q14. MAT 16Z is used for both residential and non-residential work, per PG&E's response to DR-ORA-178-Q17, but is classified as non-residential work in Ex. PG&E-4.

[160] Upgrades due to PEVs are tracked via MAT codes 161-164 as discussed in SectionVII.B.4. below.

[161] Ex. PG&E-4, p. 17-11.

[162] PG&E's response to DR-ORA-Oral-25, Attachment 1, provided 2015 recorded costs by MAT code. ORA assigned costs for each MAT to residential, non-residential, PEV, and transformers per PG&E's Table 17-5 and filtered the data to get values of $96.274, $145.463, $4.408, and $100.472 million respectively. $8.827 million of 2015 MWC 16 expenditures did not have a MAT assigned and ORA classified these as "other" in line 6 of Table 10-6. See Ex. ORA-10 Workpapers, part 1.xls, "MWC 16 2015" tab.

2. Non-residential Expenditures

Expenditures for line extensions and new service equipment for new non-residential customers categorized by MAT codes in lines 13-20 in Table 17-5.[163] Non-residential customers include customers in the commercial, agricultural, and non-energy utility business sectors. While the total cost of installing new electric infrastructure is shared between PG&E and the customer requesting the service, as detailed in PG&E's service tariffs (Electric Rules 2, 15, and 16), PG&E's recorded and forecast expenditures are provided net of all customer contributions.[164]

Expenditures for non-residential connections are shown in line 2 of Table 10-6. ORA uses recorded 2015 expenditures of $145.463 million, which are $29.3 million lower than PG&E's forecast.[165] ORA is not recommending adjustments to PG&E's 2016 or 2017 forecast values.

3. Line Extension Reporting Requirements

PG&E proposes that the Line Extension reporting requirement mandated in Ordering Paragraph 1 of the Commission's decision in PG&E's 2003 GRC (D.04-05-055) be discontinued. PG&E asserts that the production of this report is "quite burdensome, with very limited feedback provided or questions received regarding its content."[166] ORA reviewed these reports as part of its analysis and plans to do so

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[163] Ex. PG&E-4, p. 17-11. MAT 16Z, line 20 of Table 17-5, is used for both residential and non-residential work, per PG&E response to DR-ORA-178-Q17, but is classified as non-residential work in Ex. PG&E-4.

[164] Ex. PG&E-4, p. 17-11.

[165] PG&E's response to DR-ORA-Oral-25, Attachment 1, provided 2015 recorded costs by MAT code. ORA assigned costs for each MAT to residential, non-residential, PEV, and transformers per PG&E's Table 17-5 and filtered the data to get values of $96.274, $145.463, $4.408, and $100.472 million respectively. $8.827 million of 2015 MWC 16 expenditures did not have a MAT assigned and ORA classified these as "other" in line 6 of Table 10-6. See Ex. ORA-10 Workpapers, part 1.xls, "MWC 16 2015" tab.

[166] Ex. PG&E-4, p. 17-37.

in subsequent GRCs and therefore recommends that PG&E continue producing these reports.

4. PEV Expenditures

Line 3 of Table 10-6 above provides recorded and forecast expenditures where load checks for plug-in electric vehicles (PEV) result in "upgrades of the service directly serving the customer, and the secondary distribution and transformers supporting that service."[167] PG&E clarifies that "PEV capital improvements can be caused directly by new PEV load, or may be made as a result of conducting a PEV related load check that finds an existing overload situation on PG&E's service and distribution facilities."[168]

ORA uses recorded 2015 expenditures of $4.408 million in line 3 of Table 10-6, which are $4.941 million lower than PG&E's forecast. ORA recommends an alternative forecast to PG&E's for 2016 or 2017 as discussed below.

PG&E's forecast for each year 2015-2017, is the product of the estimated unit cost per upgrade and a forecasted number of upgrades. ORA first reviewed PG&E's estimated unit cost. PG&E used the three-year average of 2012-2014 data to get a unit cost of $16,849, which was escalated to get values for 2015-2017.[169] PG&E provided no explanation or evidence to support the exclusion of the 142 projects in 2011.[170] Including the 2011 projects gives a four-year average unit cost of $14,932.[171]

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[167] PG&E's response to DR-ORA-31-Q1. This response notes that upgrades to the primary system that may be required are included MWC 06.

[168] Ex. PG&E-4, p. 17-32.

[169] Ex. PG&E-4-WP, WP Table 17-32, line 12. Note that Ex. PG&E-4, p. 17-32 incorrectly states the three year average is $20,705, but this is the 2014 value as shown in Ex. PG&E-4-WP, WP Table 17-32, line 11.

[170] Ex. PG&E-4-WP, WP Table 17-32, line 7.

[171] In Ex. PG&E-4-WP, WP Table 17-32, PG&E applies historic escalation rates (line 10) to historic expenditures (line 11) to get its three-year average of $16,849. A simple average

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ORA then considered the number of upgrades or units per year. As detailed in Ex. PG&E-4-WP, WP Table 17-32, PG&E's units relies on a number of layered forecasts. First, PG&E estimates the new or "incremental" PEVs in its service territory.[172] Second, PG&E forecasts the number of PEV customers on an EV rate.[173] Taken together, these provide PG&E's forecast of customers that will engage with PG&E regarding their PEV service, which sets the upper bound on the number of upgrades that could be performed.[174] Finally, PG&E calculates the ratio of upgrades to EV rate customers based on historic data from 2011-2014 to calculate an average rate of 5.8%.[175] PG&E's forecast for upgrade units in 2015-2017 is the product of 5.8% and the annual forecast of EV rate customers.[176]

ORA found three issues with PG&E's unit forecast. First, while the average ratio of PEV owners on an EV rate was historically 27%, PG&E used a 31% value in 2015 that increased 2% annually to 35% in 2017.[177] This is based on an unsupported assertion that this proportion is "forecasted to increase over time as PG&E continues to enhance education & outreach activities and availability customer support tools for EV customers."[178] Second, PG&E's assumption that 5.8% of PEV owners on an EV rate will require an upgrade is based on a simple

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yields $16,361. ORA applied the same process, as is shown by the forecast value of $14,932 being higher than the simple average of $14,351.

[172] Ex. PG&E-4-WP, Table 17-32, lines 2 and 5.

[173] Ex. PG&E-4-WP, Table 17-32, line 8 provides the annual rate by dividing line 7 data by line 6 data.

[174] PG&E cannot perform load checks or perform distribution system upgrades for customers when it does not know the customer has a PEV.

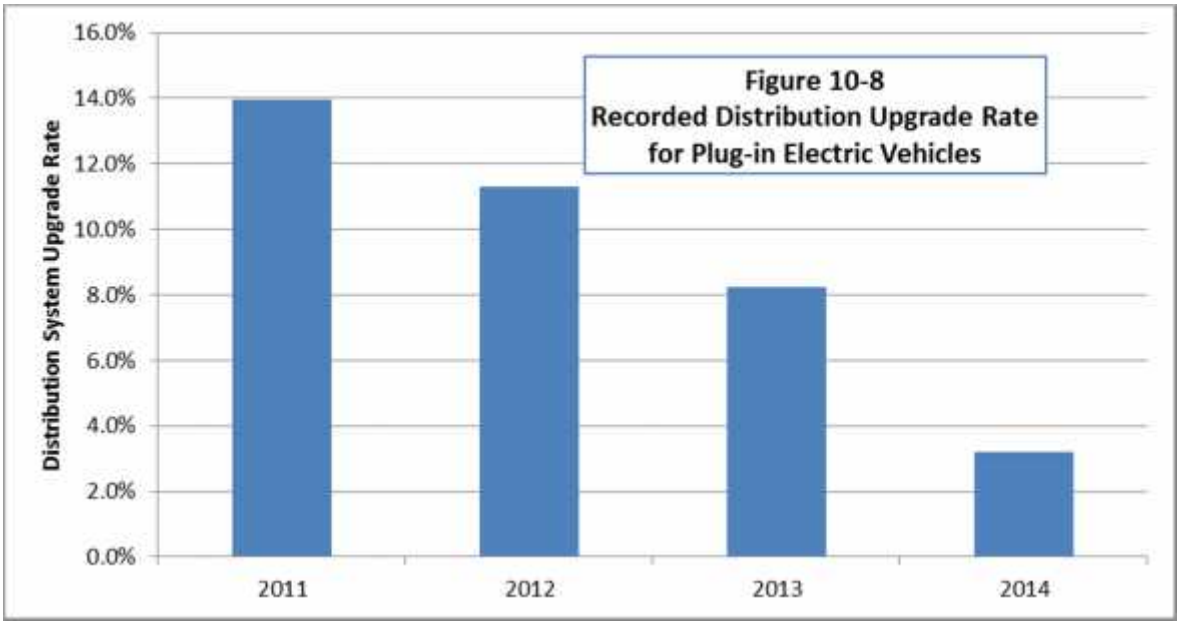
[175] Ex. PG&E-4-WP, Table 17-32, lines 8 and 9.

[176] Ex. PG&E-4-WP, Table 17-32, line 7.

[177] Ex. PG&E-4-WP, Table 17-32, line 4.

[178] Ex. PG&E-4-WP, Table 17-32, FN 3.

average that does not reflect the clear downward trend in this ratio, from 14% in 2011 to 3.2% in 2014 as shown in Figure 10-8 below.[179]



Third, PG&E's 2015 forecast for PEV related upgrade costs of $9.349 million was more than twice the recorded value of $4.408 million, as shown in line 3 of Table 10-6 above.

ORA's research indicates there is an inverse relationship between gasoline prices and purchases of high-efficiency automobiles, including PEVs.[180] Gasoline prices tumbled the second half of 2014, hit an eight-year low in January 2016, and are projected by the U.S. Energy Information Administration (EIA) to stay low through 2017:[181]

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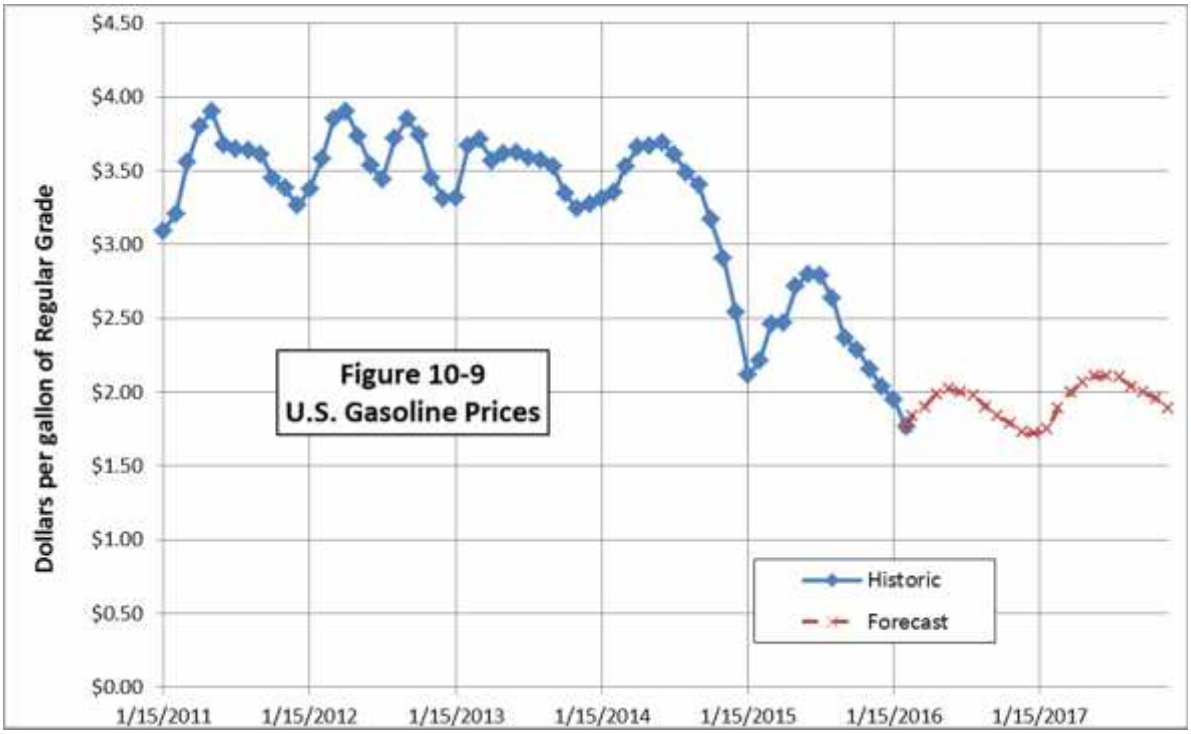
[179] Ex. PG&E-4-WP, Table 17-32, line 8.

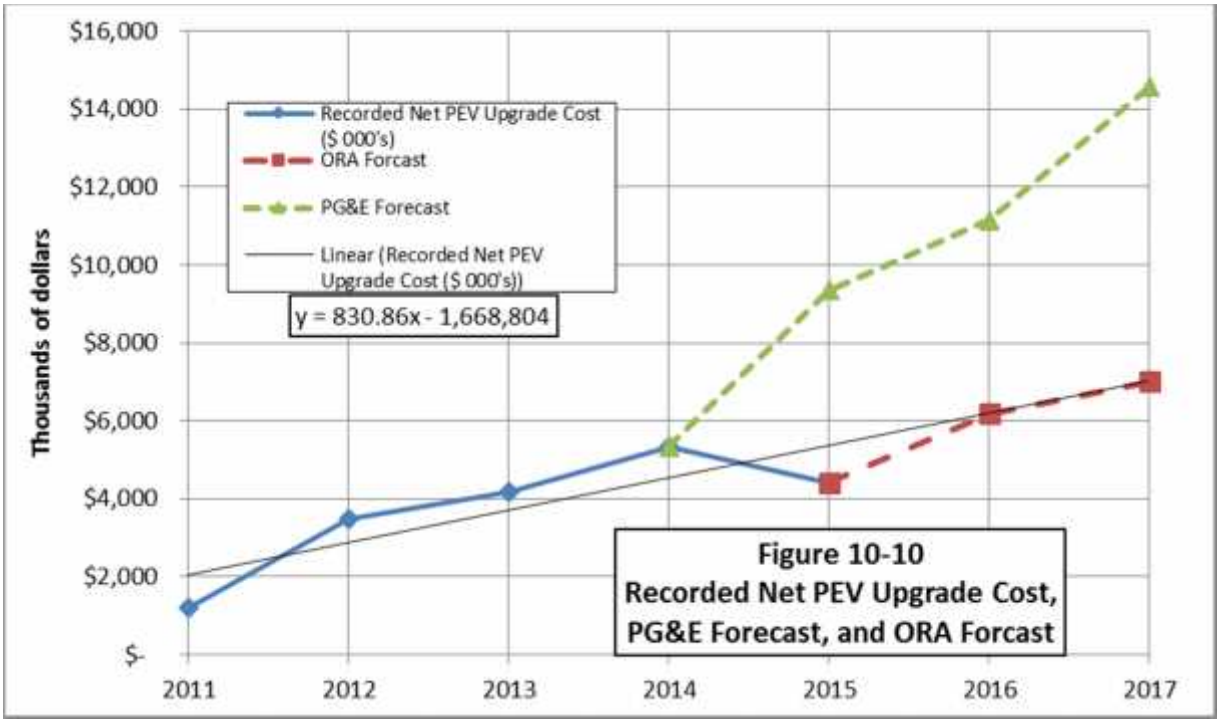
[180] A Google search on "gas prices and electric vehicles" provides ample evidence of this relationship, for example http://fortune.com/2016/01/21/low-gas-prices-derail-president-obamas-electric-car-goals/.

[181] See Ex. ORA-10 Workpapers, Part 4, "Petrol" tab. All data for U.S. nationwide retail price for regular grade gasoline, downloaded from EIA website on March 22, 2016. Forecast data from EIA short term energy outlook at http://www.eia.gov/forecasts/steo/.



Given this independent prediction of low gasoline prices through 2017, ORA estimates that PEV purchases in PG&E's service territory will be significantly lower than PG&E's forecast. However, ORA also believes that precise predictions of PEV sales is difficult, given the volatility of gas prices, the uncertainty of how PEV battery production will evolve, and the limited historic data available to determine an accurate correlation between gasoline prices and battery costs and PEV sales. Therefore, rather than make adjustments to each line item in Ex. PG&E-4-WP, WP Table 17-32 of PG&E's forecast, which fundamentally depends on PEV sales, ORA used a simple linear trend of 2011-2015 PEV upgrade costs to forecast 2016 and 2017 expenditures.[182]

[182] Figure 10-10 below provides ORA's forecast including escalation. Values in line 3 of Table 10-6 are net of PG&E escalation, but escalation at the same rate is included in line 8 of Table 10-6.



This forecast provides for an increase in expenditures in spite of the historic declining rate of distribution upgrades per PEV customer on an EV rate previously noted. It also encompasses ORA's finding that the average unit for 2011-2014 is lower than the three-year average used by PG&E. ORA's forecast for 2016 is $6.001 million compared to PG&E's $11.114 million, and for 2017 is $6.584 million compared to PG&E's $14.552 million, excluding escalation.[183]

5. Transformers

MWC 16 includes the cost of line transformers purchased for "revolving stock" and transformers that are scrapped, as shown in Table 10-6 above, lines 4 and 5.[184]

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[183] ORA's analysis as shown in Figure 10-10 uses the trend in recorded data to establish a 2016 forecast of $6.174 million for 2016 and $7.005 million for 2017. These values include escalation. The values provided here and in line 3 of Table 10-6 do not include escalation since this is added back in line 8.

[184] Line transformers included in MWC 16 include a wide range of transformers used downstream of substations, including instrumentation transformers with an average unit cost of $209 in 2014, overhead service transformers, and pad-mounted transformers for large

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PG&E tracks transformer purchases using MAT 160, but has no MAT for transformer scrapping expenditures, and 2015 recorded expenditures provided by PG&E do not provide expenditures for transformer scrapping.[185] ORA's 2015 forecast for transformer purchase and scraping expenditures is the sum of recorded expenditures for purchases, scrapping, and "other" MWC 16 expenditures that were not assigned an MAT code. ORA reduces PG&E's 2016 and 2017 forecast values based on an issue with one line item in PG&E's analysis.

PG&E increased the unit costs for all types of transformers purchased in 2016 and 2017 by 12% based on "DOE transformer efficiency standards."[186] This is in addition to the escalation that PG&E applied to all capital expenditures.[187] During discovery, ORA asked PG&E to "provide documents, data, and analysis supporting cost increases due to "DOE Efficiency Standards rates, Ex. PG&E-4-WP, WP Table 17-38, Line 18" and PG&E was able to provide no support for the purported 12% cost increase.[188] PG&E's response indicates that PG&E is willing to "take" a material price increase offered by vendors rather than leverage its position as a high volume, high value customer to negotiate a lower price. Since this claim for a 12% increase lacks support, ORA's forecast for 2016 and 2017 excludes this increase

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customers with an average unit cost of $11,487 in 2014. See Ex. PG&E-4-WP, WP Table 17-38, lines 12-15.

[185] PG&E response to DR-ORA-Oral-25- Q1, attachment 1. ORA Table 10-6 does not show scrapping costs for 2015, but instead $8.8 million for "other" costs where PG&E did not assign an MAT to expenditures. While this does not impact ORA's forecast since no adjustments are proposed for transformer scrapping expenditures, ORA recommends that going forward PG&E assign a MAT to scrapping expenditures so these expenditures can be accurately tracked.

[186] Ex. PG&E-4, p.17-34, and WP Table 17-38, line 18 and calculations embedded in lines 21-24.

[187] Ex. PG&E-4-WP, WP Table 17-38, line 17 and calculations embedded in lines 21-24.

[188] PG&E's response to DR-ORA-28-Q1. PG&E's response in whole: "The forecast for cost increases due to "DOE Efficiency Standards" were based on oral communications with several of PG&E's suppliers of transformers in early 2015. There are no documents recording these conversations."

and is 12% lower than PG&E's. ORA's forecast for 2016 is $85.110 million compared to PG&E's $96.716 million, and for 2017 is $88.998 million compared to PG&E's $101.134 million, excluding escalation.

C. Recommendation Regarding Tracking MWC 16 Expenditures

In 2015, PG&E recorded $8.827 million to MWC 16 without an MAT code to indicate the type of work performed. In parallel, PG&E forecasted $5.252 million for transformer scrapping which does not have an MAT code. ORA recommends that PG&E assign a new MAT code for transformer scrapping to provide greater transparency into its expenditures in subsequent GRCs.

ORA also recommends that PG&E use its existing MAT codes, or add additional codes, to provide greater transparency for non-residential connection expenditures. Non-residential connection unit costs have more than tripled from $4,359 in 2006 to $13,941 in 2015.[189] ORA sought to understand if this increase was due to a structural shift from lower to higher cost customers, such as from small commercial to large agricultural, or if it was due to poor cost-control by PG&E. These efforts were hindered by differences in how PG&E tracks expenditures vs. connections: PG&E tracks expenditures at the MAT level, but not customer connections.[190] Connection data is only parsed for non-residential connections between general customer types, e.g, agricultural vs. commercial.[191] ORA recommends that non-residential expenditure and connection data need to be

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[189] 2006 data from Ex. PG&E-4-WP, WP Table 9-30, line 76, from PG&E's 2014 GRC, A.12-11-009. 2015 unit cost calculated by ORA: $13,941 = $143.463 million divided by 10,434 connections. 2015 non-residential recorded cost of $145.463 million is from PG&E's response to DR- ORA-Oral-25, Attachment 1, filtered by ORA as shown in Ex. ORA-10 Workpapers, part 1.xls, "MWC 16 2015" tab. 2015 connections of 10,434 provided in PG&E's response to DR-ORA-172-Q1.

[190] PG&E's response to DR-ORA-107-Q15.

[191] PG&E's response to DR-ORA-107-Q12, Attachment 1. However, PG&E's response to DR-ORA-107-Q13 indicated the highest level of resolution for non-residential unit costs was between agricultural and "Other Non-residential" customers.

provided at the MAT level to allow the Commission and parties to review the cause of this tripling of unit costs in less than ten years.

VIII. WITNESS QUALIFICATIONS

My name is Thomas Roberts. My business address is 505 Van Ness Avenue, San Francisco, California. I am employed by the California Public Utilities Commission as a Senior Utilities Engineer in the Office of Ratepayer Advocates Energy Safety and Infrastructure Branch.

I received a Bachelor of Science Degree in Mechanical Engineering from the California Polytechnic University in 1988, and a Masters of Business Administration from the Peter F. Drucker Center at the Claremont Graduate School in 1994. I am currently registered in California as Professional Mechanical Engineer.

Since joining the Commission in 2006, I have worked on a wide variety of proceedings, including advanced metering infrastructure (AMI), energy efficiency (EE), and avoided costs. I have served ORA as project coordinator for AMI programs, and for distributed generation programs including the California Solar Initiative (CSI) and the Self-Generator Incentive Mechanism (SGIP). I was an ORA witness in the Pipeline Safety Enhancement Plan (PSEP) applications of PG&E and the SoCalGas and San Diego Gas & Electric in 2012, in the Orders to Show Cause related to PG&E's Line 147 in 2013, in PG&E's PSEP Update application in 2014, and in PG&E's 2015 Gas Transmission and Storage (GTS) proceeding.

Prior to joining the Commission, I held various professional positions including Senior Test Engineer/Scientist, Facility Manager, and Program Manager at Boeing Space Systems, and as an applications engineer for a mechanical instrumentation manufacturer. In the former position, I conducted tests of launch rocket components and systems which simulated the mechanical stresses of launch, the transonic boundary, and on-orbit payload delivery. My responsibilities included preparing test procedures, operating National Institute of Standards and Technology (NIST) traceable instrumentation systems, ensuring the safety of personal and test specimens, ensuring test objectives were met, and documenting test results in

reports and archived data. I supervised tests of complete launch vehicles at National Aeronautics and Space Administration (NASA), Department of Defense (DOD), and subcontractor facilities nationwide.

This completes my prepared testimony.