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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2020.	Application No. 18-12-009 (Filed December 13, 2018)

OPENING BRIEF OF THE JOINT COMMUNITY CHOICE AGGREGATORS

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On behalf of the Joint CCAs

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2020.	Application No. 18-12-009 (Filed December 13, 2018)

OPENING BRIEF OF THE JOINT COMMUNITY CHOICE AGGREGATORS

Pursuant to Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC"), and Administrative Law Judge Lirag's December 2, 2019 e-mail ruling revising the schedule of this proceeding ("December 2 Ruling"),[1] East Bay Community Energy ("EBCE"),[2] Marin Clean Energy ("MCE"),[3] Peninsula Clean Energy ("PCE"),[4] Pioneer Community Energy ("Pioneer"),[5] San José Clean Energy ("SJCE"),[6] and Sonoma Clean Power ("SCP"),[7] (collectively "JCCAs" or "Joint CCAs") hereby submit this Opening Brief regarding the *Application of Pacific Gas and Electric Company ("PG&E") for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service on January 1, 2020* ("Application").

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1 A.18-12-009, *E-mail Ruling Revising Schedule of Proceeding* (Dec. 2, 2019) ("December 2 Ruling").

2 EBCE is the community choice aggregator ("CCA") for Alameda County.

3 MCE is the CCA for Marin and Napa Counties, unincorporated Contra Costa County, and the Cities and Towns of Benicia, Concord, Danville, El Cerrito, Lafayette, Martinez, Moraga, Oakley, Pinole, Pittsburg, Richmond, San Pablo, San Ramon, and Walnut Creek.

4 PCE is the CCA for San Mateo County.

5 Pioneer is the CCA for Placer County.

6 SJCE is the CCA for the City of San José.

7 SCP is the CCA for the Cities of Cloverdale, Cotati, Fort Bragg, Petaluma, Point Arena, Rohnert Park, Santa Rosa, Sebastopol, Sonoma, Willits and the Town of Windsor, and the Counties of Sonoma and Mendocino.

On December 20, 2019, PG&E, the California Public Advocates Office ("Cal PA" or "Public Advocates"), The Utility Reform Network ("TURN"), Small Business Utility Advocates, Center for Accessible Technology, the National Diversity Coalition, Coalition of California Utility Employees ("CUE"), California City County Street Light Association, and the Office of the Safety Advocate (collectively, "Settling Parties") submitted a joint motion ("Settlement Motion")[8] seeking approval of a settlement agreement ("Settlement Agreement").[9] The Settlement Agreement purports to resolve "all disputed issues the Settling Parties raised in this proceeding."[10]

The Settlement Agreement is not unanimous and does not address many of the issues that the Joint CCAs and other non-settling parties raised throughout the course of this proceeding. Thus, while "all proposals and recommendations *by the Settling Parties*" are either withdrawn or "subsumed without adoption" by the Settlement Agreement, none of the Joint CCAs' proposals and recommendations have been withdrawn or are expressly subsumed by the Settlement Agreement. As such, and recognizing the Commission may accept, reject or modify discrete components of the Settlement Agreement, the JCCAs include all of our substantive arguments and positions in this brief regarding all issues contained in PG&E's application, whether or not addressed in the non-unanimous Settlement Agreement.

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8 A.18-12-009, *Joint Motion of the Public Advocates Office, the Utility Reform Network, Small Business Utility Advocates, Center for Accessible Technology, the National Diversity Coalition, Coalition Of California Utility Employees, California City County Street Light Association, The Office of the Safety Advocate and Pacific Gas and Electric Company for Approval Of Settlement Agreement* (December 20, 2019) ("Settlement Motion").

9 A.18-12-009, *Settlement Agreement of the 2020 General Rate Case of Pacific Gas and Electric Company*, Attachment 1 to the Settlement Motion (December 20, 2019).

10 Settlement Motion at 1.

1. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

1.1 Policy Overview

PG&E's application to increase its electric generation, electric distribution and gas distribution rates will have varying impacts on both bundled and unbundled customers. The Commission must ensure PG&E's costs are just and reasonable, and also make certain there are no illegal cost shifts between bundled and unbundled providers.

A significant portion of PG&E's requested rate increases is to fund its Community Wildfire Safety Program ("CWSP"). The modifications to PG&E's CWSP the JCCAs have proposed in this case meet the urgent and extreme challenges this State faces with bolder, more targeted, fairer and more cost-effective action than what the utility has proposed. The CWSP must be expanded, accelerated and closely coordinated with local governments to ensure it complies with laws prohibiting PG&E from providing generation service to CCA customers and to increase the effectiveness of microgrid resilience zones in protecting California's most vulnerable citizens, its critical facilities, and its way of life. PG&E's proposed functionalization for CWSP costs, including the cost of resilience zones, should be revised and the cost of at least three of the helicopters that PG&E purchased should be disallowed. These changes to the CWSP ensure limited ratepayer resources are spent in the most effective manner possible and that activities are properly focused and coordinated with impacted communities.

More broadly than the CWSP, the manner in which PG&E functionalizes its costs to its various lines of business must be fair and equitable to ensure that departed load customers are paying their fair share for unbundled electric service. PG&E has failed to conduct its business or convey its rate case recommendations with sufficient detail regarding cost allocation and functionalization among its electric generation, electric distribution, and gas distribution functions. Historically, this may not have been entirely necessary as PG&E's electric customers were largely homogenous in the service they received and therefore generally agnostic to functionalization issues. However, with the substantial increase in unbundled electric customers, more attention to detail is crucial and necessary when functionalizing costs. Failure to properly distribute just and reasonable revenue increases across utility functions will have a substantial impact on the millions of customers who receive generation service from the Joint CCAs and will result in inappropriate cost subsidizations in violation of California state law and policy.

PG&E' proposal for special recovery of its hydroelectric generation costs through a nonbypassable charge ("NBC") must be rejected. It lacks specific statutory authority, expands the Public Purpose Programs ("PPP") charge beyond is statutory purposes, and duplicates existing ratemaking mechanisms already ensuring each customer pays their fair share for the utility's hydro resources. Its adoption would create an uneven competitive playing field among load-serving entities ("LSEs") while requiring the Commission to determine on an on-going basis which resources are clean or public or community-centered *enough* to deserve special rate recovery. PG&E's proposal is better suited for the Legislature.

Both PG&E's proposed hydro decommissioning and solar decommissioning costs should be rejected until the utility's next general rate case ("GRC"). PG&E's small hydroelectric generation fleet is in a state of significant uncertainty, where five of the 13 units have already been sold, have been ordered to be sold, or are in the process of being sold. With uncertain fates and decommissioning dates more than 10 years in the future, pausing rate recovery for three years will present a clearer picture regarding the likely fate of these assets with little downside.

PG&E's suggested solar decommissioning costs *are 10% greater than the cost of the original facilities*, more than twice the costs of the utility's only prior solar decommissioning experience, and many multiples of the costs solar industry reports suggest are likely. For both solar and hydro decommissioning, there is little risk to PG&E in waiting until its next GRC or in setting decommissioning accruals much lower than the utility's request: the utility will eventually be able to recover the actual costs.

JCCAs also oppose suggestions from other parties breaking from PG&E's long-standing practice of functionalizing insurance costs across all lines of business. These suggestions are based on an unsupported assumption that recent wildfires are the sole driver of recent insurance premium increases and ignores the fact that other lines of PG&E's business have also caused devastating disasters, such as the San Bruno gas explosion of 2010. In no other instance when general liability insurance premiums have gone up has the Commission attempted to allocate such costs to any particular line of business.

Finally, PG&E seeks significant recovery for its planned Grid Modernization Plan. JCCAs largely support PG&E's Grid Modernization Plan because it will enable more advanced functionality, more efficient use of electricity, and will facilitate better integration of more renewable energy on the grid. However, it is critical that the benefits of the advanced grid investments, which PG&E proposes to recover equally from CCA and bundled customers, are shared equally to those that are covering its costs. To ensure that CCA customers share in the benefits of the Grid Modernization Plan, JCCAs recommend that the Commission require that all real-time data enabled through the Grid Modernization Plan investments, be shared with all LSEs, including CCAs. Access to this real-time information will enable all LSEs to plan for generation acquisition and dispatch and participate in any future grid services markets on equal footing with PG&E.[11]

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[11] Exh. 217 at 2:6-14.

1.2 PG&E's Request

PG&E's GRC Application will increase rates for electric and natural gas service by a total of $1.058 billion in 2020, $454 million in 2021 and $486 million in 2022.[12] The utility seeks authority to increase 2020 electric distribution revenues by $749 million, an increase of 17.2%,[13] which PG&E's bundled customers, CCA customers, and other unbundled customers would pay equally. The company further seeks to increase 2020 electric generation revenues by $175 million, an 8.0% increase,[14] which CCA and other unbundled customers would pay to the extent the generation costs prove to be above-market.

1.3 Customer Impacts

JCCAs make the following specific recommendations:

- Order that PG&E's CWSP be expanded, accelerated and closely coordinated with local governments to ensure compliance with the law and increase the effectiveness of microgrid resilience zones, specifically:
    - Require that the M10 Resilience Zones program be expanded to accommodate CCA-procured energy in CCA-specified locations.
    - Require that this effort be expanded to incorporate clean, permanent generation, allowing other LSEs to participate, with the costs recovered through the PPP charge.
    - If the Resilience Zone is not expanded in the above two ways, *i.e.*, if it is approved with PG&E as the sole developer of resilience zones, the $34.1 million capital costs for the program should be removed from PG&E's

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12 Exh. 1 at 2-1:6-12.
13 Exh. 1 at 2-2:7-9.
14 *Id.* at 2-2:14-15.

distribution revenue requirement and allocated solely to the generation revenue requirement.

    - Require PG&E to greatly accelerate the identification of resilience zones.

- Order that PG&E's proposed functionalization of CWSP Costs be revised such that the costs for the operational practices, situational awareness, and support programs for the CWSP be functionalized among all of PG&E's lines of business, with expenses allocated on the basis of an appropriate O&M labor allocator and capital allocated as common plant. Order that Wildfire and Infrastructure Protection Teams (M25), Wildfire Cameras (M22), and Satellite Fire Detection Systems (M23) be functionalized in this manner as well. This recommendation reallocates $94 million in expenses and $129.3 million in capital across all lines of business.
- Adopt JCCAs recommended changes to the functionalization of certain Customer Care costs, as detailed in the following table[15]:

[15] Exh. 216 at 5:9-10.

Item	Joint CCA Proposal ($000) Electric Generation	Electric Distribution	Gas Distribution
PG&E GRC Proposal	$2,375,133	$5,267,137	$2,129,109
Impact of Joint CCA Proposed Adjustments			
Directly Functionalize Certain Customer Service Program Costs	$13,271	($12,216)	($1,054)
Adjust Remaining "Common" Customer Cost Allocator	$11,247	($10,353)	($893)
Adjust "Common" Customer Costs in Labor Allocator	$28,409	($24,032)	($4,377)
Adjustments to "Locate & Mark Activities"	$0	($9,868)	$9,868
Acceptance of PG&E's Errata	$4,650	($11,473)	$6,823
Initial Proposed Revenue Requirement	$2,432,709	$5,199,194	$2,139,475
$ Change from PG&E GRC	$57,576	($67,943)	$10,367
% Change from PG&E GRC	2.4%	-1.3%	0.5%

- Order PG&E to track utilization of customer service functions going forward to develop allocators that better reflect utilization of shared services.
- Order PG&E to provide sufficient transparency and detail in future GRC filing to justify and explain its functionalization methodologies and results.
- Require PG&E to share real-time data that is made available from its Grid Modernization Investments with all CCAs and other load serving entities, or in the alternative, functionalize some of the costs of the Grid Modernization investments to the generation function to reflect the disparate benefit that bundled customers would receive from such real-time data availability.
- Reject both Cal Advocates' and CUE's recommendations to allocate certain excess liability insurance expenses only to the electric distribution and electric transmission

functions, which if adopted, would reallocate anywhere between $238 to $300 million of these expenses.

2. LEGAL STANDARD AND RATEMAKING PRINCIPLES

2.1 Burden of Proof

The Commission is charged with ensuring that "[a]ll charges demanded or received by any public utility . . . shall be just and reasonable" and cannot approve a rate change "except upon a showing before the commission and a finding by the commission that the new rate is justified."[16] The Commission has described the utility's burden of proof pursuant to these statutory mandates as follows:

> As the applicant, [the utility] must meet the burden of proving that it is entitled to the relief it is seeking in this proceeding. [The utility] has the burden of affirmatively establishing the reasonableness of all aspects of its application. Other parties do not have the burden of proving the unreasonableness of [the utility's] showing. As the applicant in this rate case, [the utility] has the burden of proving that each of its proposals is reasonable.[17]

In this proceeding, therefore, PG&E has the burden of affirmatively establishing the reasonableness of all aspects of its application, including its proposed functionalization of costs. This evidentiary burden is entirely PG&E's; other parties do not have the burden of proving the unreasonableness of the utility's proposals.[18] The Commission has held that the utility must meet a "preponderance of the evidence" standard, that is, evidence of "a requisite degree of belief."[19] On top of this basic evidentiary burden, the Commission has found that, even for proposals focusing on important policy objectives, the utilities must demonstrate "whether the

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16 Cal. Pub. Util. Code §§ 451 and 454.

17 D.09-03-025, p. 8 (citing Cal. Pub. Util. Code §§ 451 and 454, and D.06-05-016 (SCE test year 2006 GRC)).

18 *See, e.g.*, D.09-03-025, p. 8; D.06-05-016, p. 7; D.01-10-031, pp. 8-9.

19 D.12-11-051 (SCE test year 2012 GRC), p. 9 and D.09-03-025 (SCE test year 2009 GRC), p. 8, both citing Evidence Code § 190.

program or project represents the optimal solution when considering alternatives and cost-effectiveness in the identification and prioritization process."[20]

In addition to clarifying the utility's burden of proof, the Commission has concluded that "[t]he presumption is that the existing rates are reasonable and lawful."[21] Therefore, if any requested increase to the utility's revenue requirement is not supported with sufficient information or evidence, the current amount should remain in effect as a default. In this case, other parties need not establish the requested increases are unreasonable; rather, they must do so only if the Commission has first found that the utility has met its burden of proof with respect to that request.

The Commission has also recognized that, in practice in a general rate case, the utility's burden of proof varies by proposal, based on the degree to which it is challenged by an intervening party:

> [The utility's] burden of proof is not in all areas so burdensome as one might assume. We generally rely on intervening parties to identify proposals or funding requests which should be subject to scrutiny by the Commission. Our reliance on other parties to set a framework for litigation in a general rate case derives from the fact that a single ALJ cannot review an entire rate case showing without an extraordinary expenditure of time and effort. Because intervenor resources are limited and their priorities may differ from ours, the parties may overlook proposals that the Commission might otherwise consider questionable. Nevertheless, where a proposal or funding request has not been challenged by an intervenor, we generally adopt the utility's request as a practical reality of the decision-making process. In those cases, the utility's burden of proof is indeed light.[22]

20 D.10-06-048, pp. 2-3. *See also* D.10-06-047, p. 74.
21 D.00-02-046, 2000 Cal. PUC LEXIS 239, *57.
22 D.93-12-043, 1993 Cal. PUC LEXIS 728, *12.

While the Commission recognizes where this practical reality may lighten the utility's burden, it also has concluded that, "[w]here it faces opposition, [the utility's] reasonableness showing is naturally a more difficult undertaking."[23]

2.2 Finance and Ratemaking Issues

It is axiomatic in utility ratemaking that that cost causers should be responsible for the costs that they cause. This principle is reflected in California law, which requires the Commission to "establish rates using cost allocation principles that fairly and reasonably assign to different customer classes the costs of providing service to those customer classes . . .[24] While unbundled customers are not in and of themselves a "customer class," they do utilize utility service differently from unbundled customers and pay only certain portions of the overall utility revenue requirements. Indeed, California law also recognizes this by preventing cost shifts between groups of departed and bundled customers.[25]

In particular, Section 366.2 of the California Public Utilities Code provides that "[t]he implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation."[26] Similarly, Senate Bill 790 makes explicit California's policy to "foster fair competition" between CCAs and investor owned utilities.[27]

The Commission itself has also emphasized its desire and its legal commitment to avoid any cross-subsidization.[28] In D.13-08-023, the Commission stated that it "remains committed to

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23 D.00-02-046, 2000 Cal. PUC LEXIS 239, *56-*57.
24 Cal. Pub. Util. Code § 739.6.
25 Cal. Pub. Util. Code § 366.2(a), (f).
26 Cal. Pub. Util. Code § 366.2(a)(4).
27 *See* Section 2(h) of Senate Bill (SB) 790 (Leno, 2011).
28 S*ee, e.g.*, D.13-08-023, p. 17.

ensuring that Community Choice Aggregators and other non-utility LSEs may compete on a fair and equal basis with regulated utilities."[29] As such, the Commission has committed "to consider both the mechanics and overall fairness of cost allocation …with the specific goal of avoiding cross-subsidization."[30]

California law and policy thus make clear that rates should be designed to avoid cross subsidization between bundled and unbundled customers. That is why it is particularly important that PG&E's classification in this proceeding of its costs as generation related or distribution related will have a substantial impact on CCA customers and the ability for CCAs to fairly compete.

6. ELECTRIC DISTRIBUTION

6.2 Community Wildfire Safety Program

The JCCAs and their customers know firsthand how devastating the wildfires of 2017-2019 have been for many communities.[31] The best way to honor those whose lives were lost or profoundly disrupted is to work hard and effectively to mitigate the risks of future fires.[32] PG&E correctly observes that "[w]ildfire risks cannot be addressed by a single entity, agency, or party" and "wildfire risks must be managed and coordinated across multiple stakeholders on both a local and statewide basis."[33] The JCCAs and the local governments in their respective service areas are ready to work with PG&E and other state and local agencies to meet this considerable challenge.[34]

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29 *Id.*
30 *Id.*
31 Exh. 215 at 4:9-23.
32 *Id.*
33 Exh. 16 at 2A-1:18, 20-22.
34 Exh. 215 at 4:9-23.

It is critical that wildfire risks be coordinated closely with local governments to ensure local agencies can amplify communications regarding wildfire mitigations, provide essential and emergency services to their residents during Public Safety Power Shut-offs ("PSPS") events, and prepare their citizens for any detrimental impacts.[35] Some local governments have expressed frustrations at the slow pace of coordination and communication from PG&E regarding the location, scope and duration of PSPS events.[36] This slow pace reflects the challenges associated with executing on a CWSP at the scale proposed, and emphasizes the need for strong and effective coordination with local governments and other stakeholders during the implementation of this program.[37]

To the extent the JCCAs disagree with certain elements of PG&E's CWSP in this proceeding, the intent is to offer constructive criticism, to introduce new ideas, and to refine the CWSP to ensure that limited ratepayer resources are spent in the most effective manner possible.[38] PG&E's CWSP includes significant spending totaling about $5 billion from 2018-2022.[39] This includes capital and expenses for new programs on which the utility has little experience, such as:

- Administering PSPS to curtail electric service when wildfire danger is most acute;
- Developing new "resilience zones" to provide islanded electric service during PSPS events;
- Deploying a large network of remote cameras; and
- Using new teams of wildfire protection personnel to protect PG&E assets.

In the following sections, the JCCAs demonstrate why:

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35 *Id.* at 7:11-19.
36 *Id.*
37 *Id.*
38 *Id.* at 4:9-23.
39 Exh. 16 at 1-3:8-9.

- The utility's resilience zone proposal must allow for CCA-procured generation and CCA-determined siting, and be expanded, accelerated and more closely coordinated with local governments to increase the effectiveness of microgrid resilience zones in protecting California's most vulnerable citizens, its critical facilities, and its way of life.

- PG&E's proposed functionalization for CWSP Costs, including the cost of resilience zones, should be revised.

- The cost of at least three of the helicopters that PG&E purchased should be disallowed.

These recommendations and the JCCAs' proposals in this case meet the urgent and extreme challenges this State faces with bolder, more targeted, fairer and more cost-effective action than those elements of the CWSP to which the Settling Parties agreed.

6.2.1 Community Wildfire Safety Program Overview: The Commission Should Modify the CWSP.

A. Resilience Zones Policy: Approval of PG&E's Program Should be Directly Tied to its Expansion, Acceleration and Close Coordination with Local Governments.

Recent PSPS events reinforce the record evidence in this case on the need for near-term modifications to PG&E's implementation of its resilience zone program. PG&E proposes a program to create "resilience zones" that can function as temporary microgrids with unspecified generation sources, but presumably mobile diesel generators owned or contracted by PG&E.[40] PG&E has asked only to recover the interconnection costs to create these islanded zones.[41] The JCCAs' proposal builds on this small start and seeks to create a bolder, cleaner and longer-term solution that is in line with the law, recent Commission decisions and rulemakings.[42]

In the short-term, PG&E must:

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[40] Exh. 215 at 11:7-20 and Attachment RTB-2, pp. 2-3 (PG&E Data Response to Joint CCAs DR 1, Q16(a)).

[41] Exh. 215 at 11:7-20.

[42] *Id.*

- Coordinate and collaborate with CCAs to construct resilience zones that accommodate CCA-procured generation within the CCAs' service territories;
- Incorporate clean, permanent generation within the resilience zones framework, targeting public shelters, schools, first-responders, cellular towers, and vulnerable Californians; and
- Greatly accelerate the identification of resilience zones.

In the longer-term, via R.18-12-005, R.18-10-007, or R.19-09-009, PG&E, other LSEs, other stakeholders including local governments, and the Commission should develop objective criteria to determine where resilience zones should be located. These objectives and provisions should be incorporated into the CWSP prior to the Commission allowing PG&E to recover CWSP-related costs in 2020 to 2022.

1. Resilience zones in CCA service territories must be built to accommodate CCA-procured generation and coordinated closely with CCAs and local governments.

Partnering with CCAs is required to ensure PG&E's resilience zone proposal complies with the law and is effective in meeting local needs. Given the proliferation of CCAs within PG&E's service territory, and the fact millions of CCA customers are impacted by the PSPS events, resilience zones must be located in a manner that allows CCAs and PG&E to cost effectively serve their customers during PSPS and other events. However, the utility's resilience zone proposal would only accommodate PG&E-procured generation and only allows PG&E, in its sole discretion, to determine the location in which to build the resilience zones.

Such an approach results in a scenario where PG&E will build interconnection and islanding facilities in order to serve load it cannot legally serve. Under Public Utilities Code § 366.2(a)(5), CCAs "shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator's customers…." Thus, if the Commission were to adopt PG&E's proposal without requiring collaboration with CCAs, who are already developing programs to mitigate the impacts of grid outages, PG&E would contract for generation assets, and build interconnection and microgrid facilities, that legally can only serve its bundled customers. Such an outcome is inefficient and will result in wasted resources by PG&E at a time when capital deployments must become more efficient. A better approach is to require PG&E to partner with CCAs in building these resilience zones in a CCA's service territory in places the CCAs choose and to accommodate CCA-procured generation.

Not only will coordinating with CCAs ensure the assets will be used in compliance with the law and avoided stranded assets, it will also greatly increase the program's effectiveness. To have a true Community Wildfire Safety Program, the utility must coordinate closely with local agencies in siting and developing these zones.[43] Those agencies know best where critical facilities and vulnerable populations are located. PG&E should not have sole discretion to decide the location of resiliency zones.[44] The utility has not provided sufficient details regarding how they intend to evaluate additional sites for resilience zones,[45] and there undoubtedly will be trade-offs between, for example, the fire threat in a given area and the population exposed to risk.[46] The utility is not alone in its concern with the community impacts of wildfire mitigation programs such as the PSPS.[47] The Commission and PG&E should work closely with CCAs and local governments to understand local needs and priorities in siting these zones.[48]

PG&E agreed it is critical for PG&E to know where communities have planned to locate shelters and other public services.[49] As PG&E witness Calvert admitted during cross

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[43] *Id.* at 8:12 to 9:3.
[44] *Id.*
[45] *Id.* at 13:2-9.
[46] *Id.*
[47] *Id.* at 8:12 to 9:3.
[48] *Id.*
[49] 18 Tr. 2127:4-12 (PG&E – Calvert).

examination, locating resilience zones in a place where people are unlikely to gather during a PSPS event would be imprudent.[50] For this reason, the JCCAs suggest the Commission tie authorization of the CWSP to a requirement that PG&E solicit from each county in its service territory a list of the critical infrastructure, *i.e.*, the first responder facilities, shelters, schools, and hospitals discussed in the previous section, as a starting point for where resilience zones should be created and that no resilience zone be adopted that is not a part of that list.

Eventually, the locations of the resilience zones should be based on a set of objective criteria defined by the Commission with input from all stakeholders.[51] The JCCAs recognize that the definition of these criteria will require coordination with other proceedings (*i.e.*, the wildfire planning docket, R.18-10-007, and the de-energization proceeding, R.18-12-005).[52] The JCCAs also agree with PG&E's statements in its rebuttal testimony that the implementation of resilience zones should not be delayed while a stakeholder process concludes regarding the location.[53]

However, in both the long term and the near term, the location of a resilience zone in a CCA's service territory must be coordinated with that CCA. Any approval of the CWSP should be tied to an order requiring PG&E's resilience zones to accommodate CCA-procured generation and to allow local governments, via their CCAs, to determine where in CCA service territories resilience zones will be located.

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50 18 Tr. 2127:22-26 (PG&E – Calvert).
51 Exh. 215 at 8:12 to 9:3.
52 *Id.*
53 Exh. 20 at 9-27:13 to 9-28:2.

2. Resilience zones should be expanded to include permanent, clean generation sources at public shelters, schools, first-responders, cellular towers and vulnerable Californians.

The JCCAs' proposal also would include the storage and associated electrical equipment – collectively, the "resiliency infrastructure" – that would enable essential equipment to be powered in island mode during an emergency such as a PSPS.[54] In addition, the JCCAs propose to expand the scope of the program to include the resiliency infrastructure to support emergency response facilities, public shelters, schools, cellular towers and vulnerable Californians.[55] Such expansion would depend on PG&E coordinating its activities closely with local governments and CCAs.[56]

These partnerships can leverage existing assets.[57] The JCCAs' proposal allows a CCA, local government, or school district to partner with PG&E to fund permanent on-site generation and storage for the resiliency zone, such as a solar plus storage unit that would be clean and quiet, that would provide long-term benefits, and that would not require that mobile generation and fuel be procured and brought to the site.[58] Many schools in northern California have existing solar systems.[59] A school would be a logical site to add resiliency infrastructure to enable not only school to be in session during PSPS events—addressing a key problem facing many Californians during PSPSs—but also to provide a meeting place and, if necessary, shelter when the threat of wildfire is high.[60]

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[54] Exh. 215 at 9:10 to 10:12.
[55] *See* Exh. 215 at 11:7-20.
[56] *Id.* at 9:10 to 10:12.
[57] *Id.*
[58] Exh. 215 at 9:10 to 10:12 and 11:7-20.
[59] *Id.* at 9:10 to 10:12.
[60] *Id.*

The resilience zone concept also should extend to adding resiliency infrastructure to local government emergency response and first responder facilities,[61] as well as cellular towers and facilities like hospitals and nursing homes that house the State's most vulnerable populations. PG&E's recent PSPS events show these are some of the key gaps in health and safety that need to be filled in order to ensure that Californians can endure days or weeks without power.

The model for this program could be the current mechanisms through which LSEs other than the IOUs are able to submit an application to administer energy efficiency programs.[62] The batteries and the non-interconnection distribution infrastructure needed for islanded operation could be funded through this PG&E "resilience zone" program, with LSEs able to apply for funding from all ratepayers through distribution rates via the PPP charge or another mechanism.[63] The LSEs themselves would develop and install the related clean and permanent generation.

PG&E's rebuttal testimony gives little more than lip service to the Joint CCAs' proposal, suggesting the utility will incorporate feedback as the CWSP, and the resiliency zone concept, evolves.[64] Such a wait-and-see approach is out of touch with the significant impact the utility's PSPS events have had on Californians' daily lives and the health of the State's economy in recent months. The urgency of the situation demands more action, sooner. It is a lost opportunity for this program to focus solely on the distribution facilities needed to interconnect temporary generation.[65]

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61 *Id.* at 10:12 to 11:5.

62 *Id.*

63 Exh. 215 at 11:7-20.

64 *See* Exh. 20 at 2A-28:22 to 2A-29:5 and 9-27:13 to 9-28:11.

65 Exh. 215 at 8:2-5 and Attachment RTB-2, pp. 2-3 (PG&E Data Response to Joint CCAs DR 1, Q16(a)).

The JCCAs' proposal to expand the CWSP program aligns and should be implemented in coordination with recent the Commission's recent decision to expand the Self-Generation Incentive Program ("SGIP") and the Commission's recent Order Instituting Rulemaking 19-09-009 regarding microgrids. In D.19-09-027, the Commission created a new equity resiliency carveout for SGIP to help address the critical needs resulting from wildfire risks in the state, establishing a set-aside in the SGIP budget for vulnerable households located in Tier 3 and Tier 2 high fire threat districts, critical services facilities serving those districts, and customers located in those districts that participate in low-income solar generation programs.[66] This SGIP carveout provides a helpful start to fund the storage aspect of the resiliency infrastructure for some of the first responders and communities the JCCAs' proposal would address.[67]

The Commission's R.19-09-009 is aimed at implementing SB 1339 by developing standards, protocols, guidelines, methods, rates, and tariffs that serve to support and reduce barriers to microgrid deployment, including those specifically targeted as mitigation measures

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66 R.12-11-005, D.19-09-027, p. 2 (September 12, 2019).

67 The Commission is also considering a Proposed Decision in R.12-11-005 that would expand the definition of critical facilities and equity resiliency budget eligibility. Currently, a customer must be located in a Tier 3 or Tier 2 fire threat zone and meet other requirements (*e.g.*, equity budget eligibility, medical needs, provide critical services in a community eligible for the equity budget) to qualify. The PD expands eligibility by allowing customers outside of the high fire threat zones to qualify if their electricity was shut off during two or more discrete PSPS events prior to their application for incentives.

For non-residential customers, the expansion refers to the provision of critical services in communities that experience 2 or more PSPS events. The PD also expands the list of critical need customers or sites eligible for incentives to include "Markets" (i.e., grocery and corner stores) that qualify as small businesses ($15 million or less in gross receipts over the last 3 tax years); Households that rely on electric pump wells for water; Independent living centers, defined as consumer controlled, community-based, cross-disability, nonresidential private nonprofit agency for individuals with significant disabilities (with several other qualifiers); Food banks, defined as a public or charitable institution that maintains an established operation involving the provision of food or edible commodities, or the products of food or edible commodities, to food pantries, soup kitchens, hunger relief centers, or other food or feeding centers that, as an integral part of their normal activities, provide meals or food to feed need persons on a regular basis. *See* R.12-11-005, *Commissioner Rechtschaffen's Proposed Decision re Self-Generation Incentive Program Revisions Pursuant to Senate Bill 700 and Other Program Changes*, pp. 25-52 (Dec. 11, 2019).

for PSPS events.[68] The Commission recently issued a scoping ruling in that proceeding dividing the proceeding into three tracks, with the first track concluding in Spring 2020 and addressing "the Commission's goal of deploying resiliency planning in areas that are prone to outage events and wildfires, with the goal of putting some microgrid and other resiliency strategies in place by Spring or Summer 2020, if not sooner."[69] While "Investor Owned Utility proposals for immediate implementation of resiliency strategies, including partnership and planning with local governments" is included within scope in this first track, PG&E has expressly sought to keep approval of its resilience zones out of scope of that proceeding.[70] Thus, it is appropriate and, given the urgency of these issues, necessary to consider and adopt within this case any resilience zone-related proposals such as those from the Joint CCAs.

PG&E's testimony forecasts investing over $13 million in capital on this program in 2018-2019 and then about $13 million per year in capital in 2020 and 2021, with an average cost of $1.2 million per site over the 2018-2022 period.[71] If the scope of this program is expanded as the JCCAs recommended, the costs likely would exceed the $34.1 million in capital that PG&E has estimated for 2020-2022.[72] The Commission should authorize PG&E to file a Tier 3 advice letter to justify an increase in the budget for this program if it is successful at encouraging partnerships between PG&E and local agencies to develop the expanded concept for resilience zones that the Joint CCAs have advocated and discussed above.

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68 Cal. Pub. Util. Code § 8371; Order Instituting Rulemaking 19-09-009 at 2 (Sep. 19, 2019).

69 *See* R.19-09-009, *Assigned Commissioner's Scoping Ruling for Track 1*, pp. 2-3 (Dec. 20, 2019).

70 *See, e.g.,* R.19-09-009, *Opening Comments of Pacific Gas and Electric Company (U 39 E) On Order Instituting Rulemaking*, pp. 6-7 (Oct. 21, 2019). At a workshop in December in this proceeding, PG&E announced it would be issuing an RFO to build facilities to serve "safe circuits" during de-energization events.

71 Exh. 16 at 9-25:12.

72 Exh. 215 at 13:11-13.

In rebuttal testimony, PG&E agrees with the JCCAs' suggestion to use a Tier 3 advice letter to request and justify cost increases for Resilience Zones, but it proposes using the WMPA in the meantime.[73] The Joint CCAs' do not oppose using the WMPA as the interim approach for cost recovery of expansion of the resiliency zone program. Regardless of the mechanism used, PG&E's program must be expanded to include cleaner and longer-term solutions that are in line with recent Commission decisions and rulemakings and that best respond to this critical near-term need.

3. PG&E must accelerate its pace of creating microgrid resilience zones.

The purpose of the resilience zones is to provide localized temporary power to the community shelters and other services supporting public safety during a PSPS.[74] In one year, the record shows PG&E has identified the location of, and brought into operation, ***one*** of the 40 resilience zones it has targeted to create.[75] The site in Angwin, California is the only site PG&E has confirmed is operational to date—nearly an entire year after filing its Prepared Testimony.[76] This pace *must* be increased, and any order allowing for recovery of the costs related to PG&E's resilience zones should include a provision ordering the utility to increase the pace of identification and construction of resilience zones in coordination with CCAs and local agencies.

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73 Exh. 20 at 9-27:13 to 9-28:11.

74 Exh. 16 at 9-38:14 to 9-39:3; Exh. 20 at 1-17:8-13; 10 Tr. 911:13-22 (PG&E – Abranches); 18 Tr. 2124:24 to 2125:2 (PG&E-Calvert); 18 Tr. 2124:13-23 (PG&E – Calvert).

75 18 Tr. 2127:27 to 2129:4 (PG&E – Calvert); Exh. 215 at Attachment RTB-2, p. 33 (PG&E Data Response to Joint CCAs DR 6, Q12(a)). Recent media coverage suggests PG&E may in fact have two operational resilience zones. Spector, Julian, Greentech Media, *Will PG&E's Blackouts Catalyze California's Microgrid Market?* (Nov. 12, 2019) (available at: https://www.greentechmedia.com/articles/read/will-pges-power-blackouts-catalyze-californias-microgrids-market).

76 Exh. 215 at Attachment RTB-2, p. 33 (PG&E Data Response to Joint CCAs DR 6, Q12(a)).

B. PG&E's Proposed Functionalization of CWSP Costs and the Cost of Resilience Zones Should Be Revised.

PG&E has been upfront regarding the fact that wildfires present a threat to infrastructure across all of PG&E's lines of business, including generation and gas and electric transmission and distribution.[77] Accordingly, the Joint CCAs proposed the costs for the operational practices, situational awareness, and support programs for the CWSP be functionalized among all of PG&E's lines of business, with expenses allocated on the basis of an appropriate O&M labor allocator and capital allocated as common plant.[78] The Joint CCAs also specifically advocated the Resilience Zones (M10), Wildfire and Infrastructure Protection Teams (M25), Wildfire Cameras (M22), and Satellite Fire Detection Systems (M23) be functionalized in this manner.[79]

PG&E's rebuttal testimony agrees with the Joint CCAs that some CWSP costs should be allocated to common, including those related to situational awareness, program support and emergency preparedness and response.[80] The utility states further that certain costs "related directly to distribution assets" should be allocated solely to electric distribution, including SCADA and reclose blocking; fuse savers and granular sectioning; SCADA capability upgrades for reclosers; and resilience zones ("which are permanent, 'plug and play' infrastructure that will enable temporary generation to connect to the distribution grid").[81] Except for the infrastructure related to resilience zones, the JCCAs do not oppose this treatment.

Unless the Commission expands PG&E's proposal to accommodate CCA generation, the utility cannot functionalize the generation and microgrid-related costs of the M10 Resilience

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[77] Exh. 215 at 22:12-13 and Attachment RTB-2, p. 47 (PG&E Data Response to Joint CCAs DR 7, Q10).

[78] Exh. 215 at 22:13-16; *see also* Exh. 16 at 2A-51, Table 2A-10, at lines 3-9; Exh. 216 at ii:9-12, 7:6-9, and 37:15 to 38:19.

[79] Exh. 215 at 7:21 to 13:16, 13:18 to 14:9, 18:4 to 19:20, 20:1 to 21:9 and 21:11 to 22:21.

[80] Exh. 20 at 1-5:20 to 1-6:7 and 3-7:1-15.

[81] *Id.* at 1-5:26 to 1-6:7 and 1-6:16 to 1-8:2.

Zones program as distribution costs. The best approach is to allow CCA-procured generation to interconnect to the resilience zones and to expand the proposal to include storage, with the costs recovered through the PPP charge.[82] If that approach is not adopted, *i.e.*, PG&E's proposal is approved with PG&E as the sole developer of resilience zones, the program should be functionalized as generation in keeping with Commission practices regarding interconnection facilities and costs.

The 2020 capital forecast for this program is $12.8 million and PG&E proposes to recover the costs in distribution rates.[83] PG&E witness Abranches sponsored PG&E's testimony on how these costs should be functionalized, but he repeatedly made clear during cross examination that he was unfamiliar with how such costs are functionalized in other, similar circumstances.[84] It is perhaps unsurprising, then, that PG&E's approach contradicts how the costs of interconnection facilities are treated for similarly sized, third-party developed generators and microgrids.

Key parts of the resilience zones are the proposed "pre-installed interconnection hubs," which are predetermined locations on the distribution system where PG&E would interconnect temporary generation.[85] There are three components to each interconnection hub, (1) a transformer and associated *interconnection* equipment, (2) ground grid, and (3) grid isolation and protection devices.[86] As PG&E witnesses explained during cross examination, this infrastructure serves two key purposes during a PSPS event: (1) to accommodate and protect interconnecting

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[82] *Id.* at 1-6:16 to 1-7:23.

[83] Exh. 16 at 9-25, Table 9-8; Exh. 215 at Attachment RTB-2, p.13 (PG&E Data Response to Joint CCAs DR 3, Q2(a)).

[84] *See, e.g.*, 10 Tr. 916:22 to 918:13 (PG&E – Abranches).

[85] Exh. 16 at 9-38:14 to 9-39:7, 9-40:1-4; Exh. 20 at 1-7:8-13; 10 Tr. 913:1-5 (PG&E – Abranches); 18 Tr. 2124:24 to 2125:2 (PG&E – Calvert).

[86] Exh. 16 at 9-39:4-9; 18 Tr. 2126:23-28 (PG&E – Calvert).

generation and (2) to create a small, energized microgrid. PG&E witness Calvert explained during hearing that the interconnection hubs include "facilities that will facilitate that interconnection."[87] The purpose of that infrastructure, in part, is to "to provide protection for the generation that's localized there."[88] PG&E aims to standardize the interconnection hubs to accommodate generators around 2 MW in size.[89]

The resilience zones would also include "grid isolation and protective devices."[90] At a high level, the purpose of this infrastructure is to separate the targeted load or loads from the rest of the de-energized grid and allow the creation of a small, energized, temporary microgrid during a PSPS event.[91]

The problem with PG&E's proposal is that it would assign interconnection costs to general ratepayers rather than the entity (PG&E) installing the generation facility or the microgrid. If a third-party like a CCA developed a generation facility and microgrid to facilitate its own resilience plans, that party would need to proceed through PG&E's interconnection procedures.[92] Under PG&E's Rule 21, any costs associated with that interconnection—including interconnection facilities and distribution system upgrades—are borne by the entity developing and installing the generation or the microgrid for facilities greater than 1 MW.[93] The reason is based on the principle of cost causation and on state law – the costs triggered by an Interconnection Request are the responsibility of the party triggering the Interconnection

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87 18 Tr. 2124:24 to 2125:2 (PG&E – Calvert).

88 18 Tr. 2125:25-27 (PG&E – Calvert).

89 Exh. 24 (PG&E Response to Joint CCAs DR 15, Q01); 10 Tr. 915:10-21 (PG&E – Abranches).

90 *See* Exh. 16 at 9-39:9.

91 Exh. 215 at 7:24 to 8:2; 10 Tr. 913:25 to 914:11 (PG&E – Abranches).

92 *See, generally,* Exh. 23 (pages from PG&E's Rule 21); 10 Tr. 915:11 to 916:6 (PG&E – Abranches).

93 Exh. 23 (pages from PG&E's Rule 21), Section E.4(a), (e) and Table E.2 (clearly showing that interconnection facilities and distribution upgrades are the responsibility of the "producer").

Request.[94] Here, PG&E is building infrastructure to accommodate temporary generation only it will procure. It is, therefore, the cost causer, and the entity that should pay for the related interconnection facilities.

Therefore, as currently proposed by PG&E, where the utility is the only entity identifying these locations and installing or contracting for the generation, consistency with Commission interconnection practices in other circumstances requires PG&E to functionalize resilience zones as generation costs. If the program is expanded to be a partnership between PG&E, other LSEs and local governments, as the JCCAs have proposed, more widely socializing the costs of the program through distribution rates or the PPP charge is the best approach.[95] However, if the Commission solely adopts the PG&E resilience zone proposal in the utility's testimony, and does not adopt the requirement that it accommodate CCA-procured generation in a location determined by the CCAs, or expand it as the JCCAs' suggest to include resilience infrastructure, the costs for the program should be removed from PG&E's distribution revenue requirement and allocated solely to the generation revenue requirement.

C. Aviation Resources (M26): The Cost of At Least Three Helicopters Should Be Disallowed

1. The cost of at least three of the four helicopters PG&E purchased should be disallowed.

The capital costs associated with PG&E's acquisition of at least three new heavy-lift Black Hawk helicopters should be disallowed. PG&E acquired four of these helicopters to support utility infrastructure projects and enhance wildfire safety, as an alternative to PG&E's prior practice of contracting for similar Black-Hawk heavy-lift helicopters to serve these

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[94] *See* Exh. 23 (pages from PG&E's Rule 21), Section E.4(e); Cal. Pub. Util. Code § 2812.5.

[95] As noted above, the Joint CCAs had originally proposed the capital costs for the M10 Resilience Zones program be allocated as common costs. PG&E rightfully points out in rebuttal that this program has little to do with its gas operations, for example. Exh. 20 at 1-6:16 to 1-8:2.

purposes.[96] The costs of at least three of these four assets should be disallowed in light of the fact that (1) PG&E has not experienced availability issues with its contracted helicopters that would necessitate the acquisition of four helicopters, and (2) building California's overall fire-fighting capacity, both within and outside of PG&E's service territory,[97] is not a benefit that should be funded by PG&E's ratepayers.

As JCCA witness Beach noted, PG&E's expected expenses for the four helicopters are 36% greater than its past costs for contract helicopters,[98] and in addition to these operating expenses, these helicopters add $31.5 million in rate base costs.[99] It is clear, therefore, that through these purchases, PG&E raised the total cost to ratepayers significantly, as compared to the alternative of continuing to contract for helicopters. In fact, PG&E has backed away from asserting that there are ratepayer savings associated with its purchase of these helicopters, conceding that it "did not perform an analysis to demonstrate that there are ratepayer savings associated with ownership of the 4 heavy lift helicopters."[100] To clarify its testimony, it submitted an errata to delete its prior statement that there were savings associated with this shift to ownership,[101] and further, the utility acknowledged in rebuttal testimony that "the costs of owning helicopters are higher than PG&E's historic cost of renting helicopters."[102]

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96 14 Tr. 1384:13-27 (PG&E – Glover).

97 PG&E cites building California's overall fire-fighting capacity as one of its principle justifications for these acquisitions. *See* 14 Tr. 1413:26 to 1414:21 (PG&E – Glover); Exh. 68 at 2-11:30 to 2-12:2, 2-14:3-4, 2-16:7-13, and 2-22:23-26.

98 Exh. 215 at 14:22 to 15:3.

99 *Id.*at 15:13-15.

100 *Id.*at 16:16-18 and at Attachment RTB-2, p. 24 (PG&E Data Response to Joint CCAs DR 3, Q5(c)).

101 *Id.* at Attachment RTB-2, p. 24 (PG&E Data Response to Joint CCAs DR 3, Q5(c)); Exh. 27 at 29-143.

102 Exh. 68 at 2-16:7-8.

In light of the cost increase associated with this change, PG&E has advanced two principal arguments regarding the benefits of ownership as opposed to continued leasing of these assets.[103] First, it asserts that ownership will guarantee access to helicopter resources.[104] However, as PG&E witness Glover admitted during hearings, contracting for helicopters under an exclusive-use contract provides "similar access" to the helicopters as an ownership model.[105] In addition, there have only been four instances in the last decade in which a single contract helicopter was unavailable to PG&E due to competing wildfire activities, and in those cases, the utility was able to borrow a helicopter with minimal disruption to its activities.[106] It is clear that "the acquisition of just a single owned helicopter would have been adequate to cover all recent instances in which PG&E needed a helicopter but was unable immediately to contract for one."[107]

While PG&E counters in rebuttal testimony that owning one helicopter "does not guarantee availability" in the same manner as owning four would,[108] the JCCAs clarify that their recommendation seeks to identify the *just and reasonable* costs that may be incurred to provide any additional availability needs PG&E has identified. Given the very few instances in recent history in which PG&E was unable to access a helicopter due to competing wildfire activities, it is only reasonable for ratepayers to incur the costs associated with a modest increase in helicopter capacity. Accordingly, the JCCAs recommend that the costs of at least three of the four helicopters be disallowed to reflect that the acquisition of just one helicopter would have

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[103] *Id.* at 2-16:7-13.
[104] *Id.*
[105] 14 Tr. 1423:7-22 (PG&E – Glover).
[106] Exh. 215 at 16:21 to 17:3 (citing Attachment RTB-2, p. 20 (PG&E Data Response to Joint CCAs DR 3, Q5(f))).
[107] *Id.* at 17:7-9.
[108] Exh. 68 at 2-25:6-20 (contending that owning one helicopter does not guarantee availability due to scheduled and unexpected maintenance).

been sufficient to achieve this additional availability that PG&E has identified would improve its ability to respond to fire hazards.

Second, since PG&E is proposing to make three of its four helicopters available to the California Department of Forestry and Fire Protection ("CAL FIRE") under its Call When Needed contract during fire season, the utility contends that owning these resources confers fire-fighting benefits to the state in the form of these extra helicopters that will be available during fire season.[109] In fact, during cross examination, PG&E witness Glover stated that the primary benefit of owning four helicopters versus having an exclusive use contract for two was to bring four new assets into the state, "increasing the amount of available hours and not depriving . . . other agencies from using vendors' helicopters."[110] PG&E states that while it has not quantified the benefits of the additional state-wide fire-fighting capability due to the availability of the additional helicopters in the state, "the additional fire-fighting capability provides value to PG&E's customers, many of whom live in high fire risk areas, and to the state generally since the helicopters could be used to fight fires outside of PG&E's service area."[111]

PG&E should not attempt to assume the role of determining or coordinating the appropriate state-level aviation resource response to increased wildfire risk. There are state and federal agencies like CAL FIRE and the U.S. Forest Service charged with fire protection duties and involved in making these larger strategic decisions for the state, and PG&E is ill-equipped to assume this role. Further, it violates the fundamental principles of ratemaking for PG&E to acquire these assets for the benefit of both PG&E customers and those living outside PG&E's

109 *Id.* at 2-11:30 to 2-12:2 and 2-14:3-4.
110 14 Tr. 1413:26 to 1414:21 (PG&E-Glover).
111 Exh. 68 at 2-22:23-26.

service area; it is not reasonable for PG&E ratepayers to be burdened with the cost of resources acquired to provide benefits both within and outside their service area.

Additionally, as ALJ Lau noted during hearings, PG&E's purchase of four new helicopters does not necessarily even add new resources to the state. If PG&E had instead continued with its prior practice of utilizing exclusive use contracts with vendors, these vendors may very well have responded to increasing demand from both PG&E and other entities contracting for their assets by deciding to purchase more helicopters.[112]

Because neither of PG&E's main justifications for these acquisitions is well supported, the capital costs associated with PG&E's acquisition of at least three heavy-lift Black Hawk helicopters should be disallowed.

2. PG&E proposes an appropriate allocation for helicopters costs.

The JCCAs support PG&E's established method to functionalize its aviation expenses based on the function that the aviation resource supports, using chargebacks to the line-of-business that uses the helicopter.[113] The JCCAs also find reasonable PG&E's proposal to allocate the capital for the helicopters to functions based on labor ratios.[114]

6.20 Grid Modernization Plan: PG&E's Grid Modernization Plan Should Benefit All Customers Equally; Otherwise Cost Recovery Should Reflect Disparate Allocation of Benefits.

The JCCAs largely support PG&E's Grid Modernization Plan because it will enable more advanced functionality, more efficient use of electricity, and will facilitate better integration of more renewable energy on the grid. However, it is critical that the benefits of the advanced grid

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112 14 Tr. 1416:12-21 (ALJ Lau).

113 *See* Exh. 215 at Attachment RTB-2, pp. 1, 19 (PG&E Data Response to Joint CCAs DR 1, Q7(a) and DR 3, Q5(b)(i)). *See also* Exh. 80 at 9-10:12 to 9-11:8 (describing how the capital expenditures are allocated).

114 Exh. 215 at 17:21 to 18:2.

investments, which PG&E proposes to recover equally from CCA and bundled customers, are shared equally to those that are covering its costs. PG&E proposes to assign 100% of the grid modernization costs to the electric distribution function, so that bundled and unbundled customers would pay for the infrastructure on an equal basis.[115]

To ensure that CCA customers share in the benefits of the Grid Modernization Plan, the JCCAs' primary recommendation (as detailed in the following section) is that the Commission require that all real-time data enabled through the Grid Modernization Plan investments, be shared with all LSEs, including CCAs. Access to this real-time information will enable all LSEs to better plan for generation acquisition and dispatch.[116]

However, in the event that IOUs are not required to share such real-time data, JCCAs recommend that the Commission allocate some portion of grid modernization costs to the generation function to reflect benefits provided solely to bundled customers.[117] If real-time data is not shared with CCAs and other LSEs, they will not realize the full benefits of the grid modernization investments that they would pay for under PG&E's proposed cost allocation. In the absence of data sharing, PG&E's bundled customers should bear more of the costs of the Grid Modernization Plan to reflect the disparate benefits that such customers would enjoy.

6.20.1 Non-Financial Issues: The Commission Should require PG&E to Share Real-Time Data that is Produced via the Grid Modernization Investments, with All LSEs, including CCAs.

PG&E states that "[t]he goal of IGP is to modernize PG&E's grid with improved situation awareness, operational efficiency, cybersecurity, and DER integration capabilities to meet today's challenges while also positioning the grid to meet the demand of a dynamic energy

115 Exh. 17 at 19-1:7-11.
116 Exh. 217 at 2:6-14.
117 *Id.* at 2:14-17.

future."[118] As such, PG&E plans to implement multiple projects to collect and utilize real-time data for planning and operations. Such real-time data would also be useful to CCAs and other LSE in provision of generation as well for their planning and operations.

The proposed IGP includes a variety of advanced components that can 1) enable new markets to provide grid (aka "ancillary") services, 2) provide LSEs tools to better plan their generation procurements and better cite DERs, and 3) would allow LSEs to maximize their investments by verifying the economic performance of existing DER programs. Each of these functions can provide benefits to any LSE that has access to the real-time data that the Grid Modernization Plan investments enable. Because PG&E proposes to assign the costs of this program to the distribution function, both CCA customers and PG&E customers will share equally in its costs and should therefore also share equally in its benefits.

A. Because PG&E Seeks Cost Recovery for Investments that are Necessary to Create a Future Market for Distribution Services, which Can Only be Monetized with Access to Real-Time Data, PG&E Should Not be the Sole Owner of Such Data.

Part of PG&E's Grid Modernization Plan includes the installation of an Advanced Distribution Management System ("ADMS"), which will bring together PG&E's current suite of planning and operations tools into an integrated, modern and scalable platform providing a single operational view of PG&E's distribution system.[119] ADMS will, among other things, enable the identification – in real-time – of grid constraints.[120] PG&E's ADMS investments will also enable it to deploy a Distributed Energy Resource Management System ("DERMS") and/or a Demand Response Management System ("DRMS"). According to PG&E, "DERMS is an emerging technology whose parameters have not yet been fully defined, but which can be

118 Exh. 17 at 19-3:1-4.
119 Exh. 17 at 19-AtchA-21:25-28.
120 16 Tr. 1795:15-18 (PG&E – Nakayama).

thought of as a software platform that can manage a variety of both aggregated and individual DERs to support various functions related to grid support, customer value, or market participation."[121] "DRMS is the IT system that processes enrollments, registration to the California Independent System Operator, management of aggregated resources, dispatch events of PG&E's Demand Response events, and retail settlements."[122]

PG&E acknowledges that in the future the real-time grid modeling capabilities of the ADMS will allow for the "[r]ealization of value streams associated with the proactive dispatch of DER to mitigate real-time and forecasted grid constraints."[123] According to PG&E the value of these future markets cannot be quantified today,[124] though "the future ability to monetize these value streams will be greatly enhanced by the establishment of the market for distribution grid services.[125] In other words, PG&E's investments in ADMS today, will create a platform for future marketplaces where DERs can provide ancillary grid services.[126] Using DERs to provide ancillary grid services to address grid constraints is potentially a valuable source of revenue for those that are able to participate in those markets.[127]

As admitted by PG&E at hearing, in order to respond to a real-time grid constraint, one would need to have access to the real-time ADMS data.[128] Nevertheless, PG&E does not plan to share such real-time data with CCAs or other LSEs, even though it acknowledges, "if a market for distribution grid services is to materialize … efforts to increase the general availability of

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121 Exh. 17 at 19-18, n. 11.
122 *Id.* at 19-18, n. 12.
123 Exh. 20 at 19-16:20-21.
124 *Id.* at 19-16:23-24.
125 16 Tr. 1798:23 to 1799:3 (PG&E – Nakayama).
126 16 Tr. 1801:18-20 3 (PG&E – Nakayama).
127 16 Tr. 1812:18-24 (PG&E – Nakayama).
128 16 Tr. 1809:4-8 (PG&E – Nakayama) (*see also*, preceding discussion starting at 1808:9); Exh. 217 at 9:21-25.

operational data will be required."[129] Despite PG&E's acknowledgement that increased operational data will be needed in the future to facilitate distribution grid service markets, it nevertheless seeks cost recovery in this proceeding, with no promise that the necessary data to participate in such markets will be available to CCAs or other third parties. If PG&E were the only entity with access to real-time grid data, it would put them at a competitive advantage in terms of effectively deploying DERs.[130] As such, and in order to ensure that PG&E is not unfairly advantaging itself in any future distribution services markets, JCCAs recommend that the Commission require PG&E to share any real-time data pertinent to DER operation and economics that is derived from its investments in ADMS.[131]

In response to JCCA's recommendation to share real-time data for purposes of providing distribution grid services, PG&E claims, without providing any support, that, "JCCA's vision for a distribution services market, wherein real-time data is shared with numerous entities jointly managing real-time dispatch of DER in response to grid constraints, is both impractical and offers no advantages relative to a centrally-managed market featuring DER dispatch governed by optimization algorithms."[132] When asked in discovery to provide support for this statement, PG&E clarified that it was merely stating *its position* is that "any future market structure should be premised on having one single grid operator manage the identification and immediate mitigation of real-time power flow issues in each service territory…"[133] However, PG&E acknowledges that such future market constructs have not yet been developed and questions

129 Exh. 217 at 3:1-4.
130 *Id.* at 9:23-25.
131 *Id.* at 12:18-25.
132 Exh. 20 at 19-20:17-22.
133 Exh. 121 (PG&E Response to Joint CCAs DR 15, Q17).

surrounding how such markets are operated are still an open question to be determined outside of the GRC proceeding.[134]

PG&E essentially asserts that it should not have to share real-time grid data, because JCCAs' vision of an open and transparent distribution services marketplace may not come to fruition if PG&E's vision of a centrally managed market is ultimately adopted. By placing itself as the sole owner of any future real-time data, PG&E is setting itself up to be the only entity with the tools necessary to operate such a market. In other words, PG&Es refusal to share real-time data makes its policy preference to have one central grid operator in control of a future grid services model a *fait accompli*. Because this GRC proceeding is not the appropriate venue to make such decisions, the Commission should ensure that real-time data is available to all LSEs as a condition of PG&E's cost recovery. That way, future conversations about market structures are not weighted in favor of PG&E as the only entity capable of operating such markets.

Indeed, prior PUC guidance indicates a preference for open and transparent access to real-time grid data and enablement of open markets. CPUC Decision 18-03-023 regarding Development of Distribution Resources Plans contemplates utilizing DER*s* to maintain and improve safety and reliability, allowing markets and customers to more fully realize the value of the resources, and ensuring *equitable access* to the benefits of DERs.[135] Similarly, D.18-03-023 notes that "wholesale energy and capacity markets are necessary to monetize the value of DERs in providing bulk system-level services and that market operations technologies to facilitate such markets include the technologies that enable market oversight and the sharing of market information as well as those that enable DER sourcing, DER aggregation, and DER portfolio

134 16 Tr. 1805:8-15.
135 D.18-03-023, pp. 33-34, OP 1.

management.[136] ADMS is indeed one of these market operation technologies that can provide the real-time information, which is critical to CCAs and other LSEs being able to perform these DER market operations.[137]

B. Because PG&E's Grid Modernization Plan Includes Investments That Will Provide Data, Which Can be Used to More Efficiently Meet Load and Site DERs, all LSEs Should Have Equal Access to Such Data.

Forecasting day ahead grid conditions would allow PG&E or any other LSE to predict the capacity requirements from DER providing and taking energy to meet local needs as well as distribution and wholesale grid needs.[138] ADMS will enable the identification in real-time of grid constraints.[139] Similarly, DRMS is the IT system that processes enrollments, registration to the California Independent System Operator, management of aggregated resources, dispatch events of PG&E's Demand Response events, and retail settlements. This visibility would be incredibly valuable to any LSE that needs to schedule generation or utilize demand response tools to meet real-time load.[140] Indeed, LSEs, including CCAs are required by California law to "first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible."[141]

Realtime data is also incredibly helpful in creating distribution hosting capacity analysis, such as PG&E's Integration Capacity Analysis ("ICA") maps. ICA maps provide grid data at all locations on the distribution system. As described Mr. Ghidossi's testimony, these maps are

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136 *Id.*, p. 7, Appendix C.
137 Exh. 20 at 19-28:13-19.
138 Exh. 17 at 19-AtchA3-1:8-10
139 16 Tr. 1795:13-18.
140 Exh. 217 at 4:6-8.
141 Cal. Pub. Util. Code § 454.5(b)(9)(C); *see also* State of California Energy Action Plan I, 2003 at p. 4 (defining a loading order with energy efficiency as the primary resource); and the Energy Efficiency Policy Manual at p. 1 (noting energy efficiency is a procurement resource and first in the loading order).

presently static and the frequency of updates is not known. The ADMS system would provide the ability for more consistent and timely updates to enable CCAs and other LSEs to determine optimal locations for new DER.[142] The CPUC ruling establishing the ICA requirement specifies that the ICA results be updated for changed circuits (*i.e.*, circuits that have been upgraded or have new DER interconnections) on a monthly basis.[143] However, upon the filing of JCCA's testimony in this proceeding, the ICA map indicated the ICA Analysis Date was December 2018.[144] At hearing, PG&E acknowledged that it had still not updated the ICA maps.[145] Providing LSEs with access to real-time data would alleviate their reliance on PG&E for capacity analysis updates. Finally, D.18-03-023 listed this capability as one of the meaningful existing and potential opportunities for DER support of the distribution system using Grid Modernization information and techniques.[146]

C. Because PG&E's Grid Modernization Plan Includes Investments That Will Allow LSEs to Evaluate the Effectiveness of DER Programs, Such Data Should be Shared.

Real-time grid information is also essential for an LSE or CCA to provide performance monitoring of DER at portfolio scale. Several CCAs already offer DER programs, including those that encourage energy efficiency, demand response and onsite generation and energy storage. Some of CCA DER programs are subject to cost effectiveness requirements that require the use of measurement and verification ("M&V"). Access to real-time grid data will allow

142 Exh. 17 at 19-AtchA3-3:11-14.
143 D.17-09-026, p. 3
144 Exh. 217 at 6:19-20.
145 16 Tr. 1803:11- 17.
146 D.18-03-023, p. 1, Appendix C.

CCAs that administer DER programs to perform M&V more cost effectively than by utilizing traditional monitoring techniques.[147]

In Rebuttal Testimony, PG&E argues that JCCA's claim that real-time data will enable better customer program M&V is based on JCCA's misunderstanding of the data's granularity.[148] PG&E clams, "calculations in ADMS are based on modeled estimates of customer usage, which are inherently of lower precision than recorded meter data and therefore not useful for M&V."[149] However, PG&E's rebuttal argument is contrary to its assertions that state estimation, a specific capability within ADMS, is "able to calculate estimated power flow values at any location on the system in real-time."[150]

While it is true that such data is "less granular" than meter data, the important point is that the data models the system in real-time, thereby showing the impacts of DER on the system specifically. Meter data is only good for evaluation after the fact and does not show the system model that is needed for M&V. MCE's 2017 requests for proposals requested bids for vendors to perform real-time monitoring of its Building Efficiency Optimization technologies,[151] that would not be necessary of it had access to PG&E's ADMS real-time data. Given that PG&E proposes to assign all of the IGP costs to the distribution function, it is not reasonable for CCAs to go out and have to pay for additional tools to perform M&V, when much of needed data could be available through real-time ADMS data sharing.[152]

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147 Exh. 217 at 10:1-30.
148 Exh 20 at 19-20:22-26.
149 *Id.*
150 Exh. 17 at 19-AtchA3-3:30-31.
151 Exh. 217 at 10:4-19.
152 *Id.* at 10:26-29.

7. ENERGY SUPPLY

7.7 Energy Supply Ratemaking

7.7.1 Hydro Non-Bypassable Charge

The Commission should reject PG&E's request for special recovery of its hydroelectric generation costs. While the Joint CCAs appreciate PG&E's long stewardship of the lands and waters associated with its hydro system, and do not contest PG&E's recovery of these costs from the ratepayers who receive power from and benefit directly from the hydro system, the proposal is deeply flawed and falls well short of meeting the utility's burden in this case.

PG&E's proposal would shift approximately $160 million in hydroelectric generation-related costs into an NBC (*e.g.*, Electric PPP) that CCA and other unbundled customers would pay.[153] PG&E estimates that the Hydro NBC would include $83 million in unrecovered historical costs (i.e. undepreciated capital from rate base), $70 million in capital costs from 2018-2022, and over $7 million per year in expenses in 2019-2020.[154]

There are numerous legal, ratemaking and policy factors undermining the utility's $160 million proposal. Specifically:

- Unlike other NBCs the Commission has approved, no specific statutory authority exists for the creation of the Hydro NBC;
- The Hydro NBC would inappropriately expand the Public Purpose Programs charge beyond its statutory boundaries;
- The Hydro NBC is duplicative of existing ratemaking mechanisms ensuring bundled customer indifference to departing customers and customers participating in DG programs;
- The Hydro NBC is bad policy because (1) it creates an uneven competitive playing field and (2) requires the Commission to referee which resources are *clean enough* or *public*

[153] Exh. 146 at 8-25:3-6; 19 Tr. 2189:8-16 (PG&E – Maggard).
[154] Exh. 146 at 8-26, Table 8-11; 19 Tr. 2188:1-15 (PG&E – Maggard).

enough or *community-centered enough* to deserve special rate recovery socializing certain costs; and

- The allocation of PG&E's generation costs is better considered at the Legislature or other Commission proceedings.

The following sections address each of these shortcomings in turn.

A. Unlike Other Commission NBCs, No Specific Statutory Authorization Exists for the Hydro NBC.

To the JCCAs' knowledge, the Commission has not created an NBC without express statutory authority to do so. The Department of Water Resources bond charge,[155] the Cost Allocation Mechanism,[156] the Power Charge Indifference Adjustment ("PCIA"),[157] the Competition Transition Charge,[158] the Cost Responsibility Surcharge,[159] the Tree Mortality NBC,[160] the Wildfire NBC,[161] and the PPP charge, for example, all stem from legislatively granted statutory authority. No statute requires or expressly authorizes the Commission to create an NBC for generation-related environmental mitigation costs caused by decades-old resources.

B. The Hydro NBC Would Inappropriately Expand the Public Purpose Programs Charge Beyond its Statutory Boundaries.

Without an express statutory mandate, PG&E proposes to force the Hydro NBC through its PPP charge. However, the utility's request exceeds the statutory boundaries defining those public benefit programs. As PG&E noted in discovery,[162] the PPP NBC was first created via AB

155 AB 1X ((Stats. 2001 (1st Extraordinary Sess.)), ch. 4.); codified at Water Code section 80000; D.02-11-022 at 3-4; D.18-10-019 at 4-6.

156 SB 695 (2009).

157 Cal. Pub. Util. Code §§ 365.2, 366.2 and 366.3; *see also* AB 1X (((Stats. 2001 (1st Extraordinary Sess.)), ch. 4. – codified at Water Code section 80000); D.18-10-019 at 4-9.

158 AB 1X (((Stats. 2001 (1st Extraordinary Sess.)), ch. 4. – codified at Water Code section 80000); D.02-11-022 at 3-4; D.18-10-019 at 4-6.

159 *Id.*

160 SB 859 (Stats. 2016, ch. 368).

161 D.19-10-056 at 5-6 (citing AB 1054 as the statutory authority for creating the charge).

162 Exh. 215 at Attachment RTB-2, p. 7 (PG&E Data Response to Joint CCAs DR 2, Q8(d), (e)).

1890 in the 1990s, pursuant to Public Utilities Code Section 381.[163] Sections 381 and 382, the latter of which is specifically referenced in Section 381, allow recovery through the PPP of only specified costs, including the following costs, as determined in numerous Commission decisions since the 1990s:

- Low-income programs;[164]
- Energy efficiency and conservation;[165]
- Demand-side management;[166]
- Research and development;[167]
- Low emission vehicles and electric vehicles;[168]
- Women, minorities and disabled veterans' business enterprises;[169] and
- Renewable energy, specifically, the "[i]n-state operation and development of existing and new and emerging eligible renewable energy resources, as defined in Section 399.12."[170]

While PG&E's Rebuttal Testimony correctly states the PPP has been expanded to include cost recovery for certain programs, it ignores the fact that each program for which costs are recovered through the PPP has a statutory basis in either Cal. Pub. Util. Code Section 381 or 382. For example, under the category of public purpose programs for low-

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163 AB 1890 (1996).

164 Cal. Pub. Util. Code § 382 (referenced in Section 381).

165 *See* R.98-07-037, D.99-03-056 (March 18, 1999); Resolution E-3529, *Pacific Gas and Electric Company Requests Approval to Establish Three New Energy Efficiency and Public Purpose Balancing Accounts and Authorized Electric Low-Income Direct Assistance Program Funding* (October 8, 1998). *See also* R.13-11-005, D.14-10-046, pp. 8, 161 (October 24, 2014).

166 A.96-12-009, D.97-08-056 (August 1, 1997); A.97-05-002, D.98-09-004 (September 3, 1998).

167 A.96-12-009, D.97-08-056 (August 1, 1997).

168 *Id.*

169 *Id.*

170 Cal. Pub. Util. Code § 381. *See also* A.96-12-009, D.97-08-056 (August 1, 1997).

income customers, the Commission has allowed cost recovery for each of the following via the PPP:

- Disadvantaged Communities Green Tariff and Community Solar Green Tariff programs;[171]
- Disadvantaged Communities Single-family Solar Homes;[172]
- Costs related to programs serving disadvantaged communities in the San Joaquin Valley;[173]
- Energy Savings Assistance;[174]
- California Alternate Rates for Energy Program;[175] and
- Community Help and Awareness of Natural Gas and Electricity Services (CHANGES) Pilot Program.[176]

The Tree Mortality NBC that PG&E cites in its Rebuttal Testimony fits within the category of renewable energy resources.[177] Numerous other energy efficiency,[178] research and development,[179] and renewable energy programs[180] have also been funded via the PPP.

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171 A.18-05-015, D.19-04-010 (April 25, 2019).

172 R.14-07-002, D.18-06-027 (June 21, 2018).

173 R.15-03-010, D.18-08-019 (August 23, 2018); R.15-03-010, D.18-12-015 (December 13, 2018).

174 Resolution G-3532, *Approves, with certain budget modifications, Southern California Gas Company's (SoCalGas) California Alternative Rates For Energy (CARE) and Energy Savings Assistance (ESA) programs conforming Advice Letters 5111-A and 5111-B filed in compliance with Decision 16-11-022* (December 14, 2017); A.11-05-017 et al, D.14-08-030 (August 14, 2014).

175 Resolution E-4884, *Resolution approving San Diego Gas & Electric Company's California Alternative Rates for Energy (CARE) and Energy Savings Assistance (ESA) programs conforming advice letters (No. 3065-E/2568-G and 3065-E-A/2568-G-A) filed in compliance with Decision 16-11-022* (December 14, 2017).

176 A.14-11-007 et al, D.15-12-024 (December 17, 2015).

177 Exh. 71 at 8-9 n. 36. *See* SB 859 (Stats. 2016, ch. 368); A.16-11-005, D.18-12-003 (December 13, 2018).

178 Statewide Marketing, Education and Outreach Program (2019 Cal. PUC LEXIS 22 (January 10, 2019)); EE program funding for Golden State Water Company, on behalf of its Bear Valley Electric Service Division (GSWC/BVES) (2016 Cal. PUC LEXIS 112 (February 25, 2016)); EE program funding for PacifiCorp (plus demand side management programs) (2014 Cal. PUC LEXIS 171 (April 10, 2014)); and EE program funding for Marin Energy (2012 Cal. PUC LEXIS 820 (August 23, 2012)).

179 Measurement and evaluation of the NEM successor tariff (2018 Cal. PUC LEXIS 450 (September 27, 2018)).

However, the Joint CCAs cannot find a single instance in which the Commission allowed the cost of a program to be funded via the PPP that stems from a cost category outside of the original PPP categories. PG&E's rebuttal testimony does not reference one either.[181]

The Hydro NBC bears zero relationship to any of public purpose program categories in California statute. The closest category of costs to which a GHG-free hydroelectric resource might fit is renewable energy resources. However, that section references Section 399.12, which contains the definition of RPS-eligible renewables, which excludes large hydro over 30 MW.[182] As a result, virtually all of the costs that PG&E would place in the Hydro NBC are <u>not</u> costs for "renewables" as defined in Section 399.12.[183] Further, the Commission has limited the use of the "renewable energy resources" part of the PPP to fund RD&D and emerging technologies, which is far different than what is proposed here for aging technologies developed in the early 20th century.[184]

The costs PG&E seeks to include in the Hydro NBC do not fit within the definition of public purpose costs set by these categories within Sections 381 and 382. The Hydro NBC inappropriately expands the Legislature's statutory mandate with regard to the PPP. It also

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180 California Solar Initiative and Self-Generation Incentive Program (2017 Cal. PUC LEXIS 360 (August 24, 2017)); Liberty Utilities Solar Incentive Program (provides incentive to help offset installation costs for residential, small business, and schools customers) (2016 Cal. PUC LEXIS 680 (December 1, 2016)); Golden State Water Company Bear Valley Electric Service Division Solar Initiative Program (provides incentive for residential customers to install PV systems) (2014 Cal. PUC LEXIS 686 (November 6, 2014)).

181 Exh. 71 at 8-9:20, n. 36.

182 *See* Cal. Pub. Util. Code § 399.12.

183 Exh. 215 at 31:2-4. *See also* Exh. 215 at Attachment RTB-2, pp. 44-46 (PG&E Data Response to Joint CCAs Data Request 6, Q16). In this response, PG&E lists the hydro facilities whose "public benefit" costs would be included in the Hydro NBC; this list includes all of PG&E's hydro plants, most of which are greater than 30 MW in size and none of which are RPS-eligible resources.

184 *See* A.15-04-012, D.17-08-030 (August 24, 2017); A.15-05-008, D.16-12-024 (December 1, 2016); A.12-02-013, D.14-11-002 (November 6, 2014). *See also* R.11-10-003, D.11-12-035 (December 21, 2011) (after funding pursuant to Section 399.8 of the Public Utilities Code expired in 2012, the Commission relied on other statutory authority to authorize funding for R&D through the EPIC program).

appears to forge a new path for Commission ratemaking where NBCs are created without any statutory requirement or express authority for it to do so.

C. The Hydro NBC is a Solution in Search of a Problem.

The Hydro NBC is a ratemaking solution in search of a ratemaking problem. The utility's main justification for the charge is a diminishing pool of ratepayers for its generation resources, singling out PG&E's usual bogeymen—CCA customers and distributed generation ("DG") customers (but not energy efficiency customers, for example)—to shoulder the blame. This thin justification fails in the light of existing mechanisms put in place to address the exact problem PG&E looks to solve, *i.e.*, to make sure each customer pays his or her fair share for PG&E's generation fleet.

1. PG&E Already Recovers Above-Market Hydro NBC Costs from All Ratepayers.

It is undisputed in this proceeding that PG&E already recovers above-market Hydro NBC costs from departed customers through the PCIA. As PG&E stated during hearing, all of the Hydro NBC costs are tied to "generation, [specifically] hydro generation,"[185] meaning PG&E recovers the NBC costs through its generation rates.[186] Because PG&E recovers all of the Hydro NBC costs through its generation rates, *all* of those costs—including the costs PG&E labels "public benefit costs"— are included in the utility's calculation of the PCIA.[187] In discovery, PG&E acknowledged that, to the extent these costs are above-market generation costs, they are already recovered from all PG&E customers – bundled and DA/CCA – through the PCIA.[188]

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[185] 19 Tr. 2190:5-15 (PG&E-Maggard); Exh. 153 (PG&E Data Response to Joint CCAs DR 2, Q8(b)).

[186] 19 Tr. 2191:2-4 (PG&E-Maggard); Exh. 153 (PG&E Data Response to Joint CCAs DR 2, Q8(f)).

[187] 19 Tr. 2191:10 to 2192:15 (PG&E-Maggard); R.17-06-026, D.18-10-019, pp. 8-9 (October 11, 2018).

[188] *See* Exh. 153 (PG&E Data Response to Joint CCAs DR 2, Q8(f).

As PG&E admits in rebuttal, the PCIA "addresses the challenge posed by departing generation customers to CCAs."[189] The PCIA recovers the "above-market generation costs that PG&E incurred on behalf of departed customers prior to their taking service from a CCA or other LSE.[190] The PCIA's purpose is "to equalize cost sharing between departing load and bundled load."[191] Its central feature is the calculation of an "indifference amount" that compares each utility's (a) total power portfolio costs, expressed in cents/kWh, to (b) a market benchmark comprised of (1) the posted forward prices for a one-year strip of power for the coming year; plus (2) a capacity adder to reflect the cost of resource adequacy ("RA") capacity;[192] plus (3) an RPS adder.[193] Because departed load customers already pay for above-market hydro costs, bundled customers only pay the at-market costs of PG&E's hydroelectric resources (plus their share of the above-market costs). Thus, the first category of customers PG&E is targeting, *i.e.*, departed CCA customers, already pay their fair share of the Hydro NBC costs.

TURN acknowledges the PCIA in its testimony but goes on to suggest controversy surrounding the PCIA's calculation supports the need for the Hydro NBC.[194] However, a 2018 decision settling that controversy directly rebut TURN's assertions.[195] TURN admits in a data request response that D.18-10-019 settled "[t]he major relevant controversy,"

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[189] Exh. 71 at 8-10:15-17.

[190] Exh. 71 at 8-10:16-20; 19 Tr. 2191:15-21 (PG&E-Maggard); Exh. 153 (PG&E Data Response to Joint CCAs DR 2, Q8(f)).

[191] D.18-10-019 at 3.

[192] *Id.* at 8-9.

[193] *Id.*

[194] Exh. 204 at 6:4-7.

[195] *See* D.18-10-019; *see also* D.19-10-001.

involving whether to include legacy Utility-Owned Generation ("UOG") in the portfolio of resources used to calculate the PCIA.[196] As TURN explains:

> [T]he Commission found that legacy UOG resources (including PG&E's hydroelectric units) should be included in the PCIA with above-market costs collected from departing customers. Unless the Commission reconsiders this element of the Decision, above-market hydroelectric UOG costs will continue to be collected via the PCIA.[197]

Thus, with the PCIA in place, and no controversy remaining on whether the PCIA includes the Hydro NBC costs, it is clear the proposed NBC is unnecessary and duplicative to address CCA departing load.

2. The Commission's Ratesetting Framework for Distributed Generation Customers Accounts for the Hydro NBC Costs.

Recognizing the PCIA "addresses the challenge posed by departing generation customers to CCAs," PG&E shifts its justification in rebuttal to assert the PCIA "does not address departing customers due to distributed generation (*e.g.*, rooftop solar)."[198] As the utility acknowledged, DG customers are still PG&E generation customers (unlike CCA customers).[199] The Commission's ratesetting framework for such customers takes into account *both* the costs PG&E's DG customers impose on PG&E's non-DG customers *and* the benefits PG&E's DG customers provide to PG&E's non-DG customers.

While PG&E's DG customers use onsite resources like rooftop solar to reduce their loads, and, therefore, may pay less towards the Hydro NBC costs than non-DG customers in

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196 D.18-10-019 at 157, Conclusion of Law ("COL") 12; Exh. 173 (TURN Response to JCCA DR 1, Q1).
197 D.18-10-019 at 157, COL 12; Exh. 173 (TURN Response to JCCA DR 1, Q1).
198 Exh. 71 at 8-10:15-17; *see also* 19 Tr. 2194:8-13.
199 19 Tr. 2193:2-12 (PG&E – Maggard).

a given month, that reduced revenue is just one cost of the program.[200] Specifically, as discussed in the Commission's Standard Practice Manual for demand side programs like net metering, decreased revenues from lower loads are one component of the tests the Commission uses to assesses the impact of DG programs on those that do not participate in them.[201] Those costs are weighed against a multitude of benefits, including "avoided supply costs," to determine whether those benefits would outweigh the costs.[202] It is upon this basis, *i.e.*, the consideration of both costs and benefits, and the costs to serve participants in DG programs, that the Commission sets rates for such customers.

The utility has all but disregarded the Commission's framework for settings rates for DG customers when asserting the Hydro NBC is necessary on account of those customers.[203] PG&E's witness admitted the utility did not take into account any benefits DG customers might provide to non-DG customers when suggesting such DG customers cause non-DG customers to bear more hydroelectric generation costs.[204] Further, she was not familiar with how the Commission assesses the impact of DG programs on unbundled customers, how the Commission's Standard Practice Manual and Avoided Cost Calculator are used to assess those programs, and whether the Commission takes into account the costs and benefits of PG&E's DG programs when setting rates for those customers.[205]

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200 *See, e.g.*, Exh. 154 at 13.
201 *Id.*
202 *Id.*
203 The utility also did not conduct a cost of service study specific to DG customers, most likely because such a study typically would take place as part of a Phase II GRC. Without either of these essential pieces, either a cost-benefit study or a cost-of-service study, the utility cannot conclude a Hydro NBC is necessary due to the impact of DG customers on non-DG customers, *i.e.*, that DG customers are not paying their fair share. The creation of an NBC on the basis that DG customers cause more costs than benefits to non-DG customers, without proving that fact, is not reasonable ratemaking.
204 19 Tr. 2197:25 to 2199:23 (PG&E – Maggard).
205 19 Tr. 2194:19 to 2197:7 (PG&E – Maggard).

The fact of the matter is the Commission already has mechanisms in place to make sure bundled customers are made whole for the Hydro NBC costs they incur due to a decline in PG&E's bundled customer revenues. The PCIA addresses departed customers. The Commission's ratemaking framework for demand side programs addresses the lost contributions to PG&E's generation costs from customers installing DG like rooftop solar.

D. The Hydro NBC is Bad Policy.

A fundamental problem with PG&E's approach is that the costs for which the utility seeks special recovery are simply environmental mitigation costs it incurred because it built, owned and operated hydroelectric plants.[206] While PG&E asks to recover these costs from all ratepayers, including CCA customers on the premise that "all citizens of California" benefit from these particular costs,[207] the record shows the local environmental benefits and increased public safety that stem from these "public costs" are simply the result of environmental mitigation required by the Commission or Federal Energy Regulatory Commission ("FERC").[208] They include costs such as "protecting natural habitat, installing and managing hiking trails, boat docks, campgrounds; and long-term monitoring of fish, wildlife, or water quality."[209] They stem from FERC's licensing requirements requiring the utility to balance beneficial uses of water resources,[210] and their purpose is to mitigate the harms resulting from damming river systems in northern California.[211]

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206 19 Tr. 2190:25 to 2191:1 (PG&E – Maggard); Exh. 153 (PG&E Data Response to Joint CCAs DR 2, Q8(b))

207 Exh. 146 at 8-24:27 to 8-25:1; Exh. 153 (PG&E Data Response to Joint CCAs DR 2, Q8(a)).

208 Exh. 146 at 8-24:21-25 and 8-25:1-2; 19 Tr. 2188:1 to 2189:1 (PG&E – Maggard).

209 19 Tr. 2189:19-24 (PG&E – Maggard); Exh. 146 at 8-25:7-32.

210 19 Tr. 2189:2-7 and 2190:8-15 (PG&E – Maggard); Exh. 215 at 23:20 to 24:6 and Attachment RTB-2, pp. 7, 11 and 30 (PG&E Data Response to Joint CCAs DR 2, Q8(b) and Q12, and DR 6, Q10).

211 Exh. 146 at 8-25:7-32; Exh. 215 at 23:20 to 24:6.

Every form of energy production has environmental impacts and must incur costs to mitigate those impacts.[212] Simply changing the name of a generation-related environmental mitigation cost to a "public benefit cost" does not change the nature of the costs and should not change the method of cost recovery.

Moreover, PG&E's proposal would create an uneven competitive playing field for generation service. There is nothing about these costs that justifies socializing them in preference to comparable costs other LSEs incur to mitigate the environmental impacts of their generation resources.[213] Other LSEs (such as the Joint CCAs) who compete with PG&E to serve unbundled ratepayers incur similar environmental compliance costs through the costs of their power purchase contracts.[214] As PG&E witness Maggard admitted during cross examination, an LSE that purchased a hydro plant from PG&E would incur these same costs.[215] It would be profoundly unfair to allow PG&E to socialize these costs among the customers of other LSEs when those other LSEs do not have the same ability to recover from all PG&E ratepayers the comparable environmental mitigation costs for their power plants.[216]

Finally, PG&E's attempt to sell the public benefits of hydro resources as "more self-contained" and "core to their purpose" than the benefits of other clean energy resources is a policymaking trap the Commission would be wise to avoid. The developers and operators of all types of renewable resources can claim, rightly, that producing environmental benefits for all Californians is "core to their purpose."[217] PG&E's suggested path would require the Commission to determine which types of energy resources provide the greatest public benefit –

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212 Exh. 215 at 23:20 to 24:6.
213 *Id.* at 24:8 to 29:18.
214 *Id.* at 24:15 to 25:12.
215 19 Tr. 2200:2-21 (PG&E – Maggard).
216 Exh. 215 at 24:15 to 25:12.
217 *Id.* at 25:24 to 26:2.

or which resources do or do not have public benefits as "core to their purpose" – and then how to reward the selected "most favored" resources by socializing their environmental mitigation costs.[218]

In fact, it is far from clear large hydroelectric resources would even be a finalist in that beauty contest. As JCCA witness Tom Beach explained in detail, there is a substantial debate about whether large hydro resources actually offer net public benefits as energy resources, given the significant environmental impacts of building the resources in the first place.[219] This debate has pitted river fisherman against lake fisherman, whitewater kayaker against motorboat enthusiast, and John Muir against the City of San Francisco.[220] It has all but halted the development of large hydro facilities in the country.[221]

At bottom, PG&E's Hydro NBC asks the Commission to weigh the public benefits provided by PG&E's hydro system in comparison to those of other energy resources, suggesting that PG&E's hydro system produces greater public benefits than other clean energy resources.[222] This debate over the relative cleanliness of different clean energy sources is neither productive nor necessary. Rejecting the Hydro NBC would avoid the need to make such a fraught decision on the relative benefits of large hydro versus other energy resources.[223] The direct beneficiaries of each type of energy resource should bear the costs to mitigate the environmental impacts of that specific resource.[224]

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218 *Id.*
219 *Id.* at 27:13 to 29:5.
220 *Id.*
221 *Id.*
222 Exh. 215 at 29:6-18.
223 *Id.*
224 *Id.*

E. Cost Allocation for PG&E's Generation Resources Are Better Considered in Other Commission Proceedings or by the Legislature.

Phase I GRCs typically set revenue requirements while the method of cost recovery from specific customer groups is left to either a Phase 2 GRC or a docket specifically dedicated to developing an NBC.[225] PG&E's proposal is more appropriate for these types of proceedings, in which the Commission and parties would expect cost of service studies to be conducted to determine how to "divide up the pie", rather than a Phase I GRC focusing on "how large the pie should be."

Even if one accepts that PG&E's hydro system benefits all Californians, the proposed Hydro NBC would recover costs from only a subset of the state's citizens.[226] Only a portion of California citizens are PG&E ratepayers, and even in northern California there are many customers of publicly-owned utilities who will not pay for the proposed Hydro NBC's costs regardless of the fate of PG&E's proposal here.[227] As PG&E witness Maggard admitted, a Sacramento Municipal Utility District or Los Angeles Department of Water and Power electric customer can recreate in a PG&E campground near a PG&E lake as easily as a PG&E ratepayer.[228] If PG&E truly believes that these costs should be allocated to "all citizens of California" who benefit from them, the utility should sponsor legislation to have these costs paid from the state's General Fund and removed from its revenue requirement.

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225 *See* A.93-12-025, D.96-04-050, pp.1-2 (April 10, 1996) (describing Phase I versus Phase II GRC issues); *see, e.g.*, A.16-11-005, D.18-12-003 (December 13, 2018) (establishing an NBC for costs associated with tree mortality biomass energy procurement via a joint application proceeding to establish the NBC).

226 Exh. 215 at 29:20 to 30:4.

227 *Id.*

228 19 Tr. 2190:18-25 (PG&E – Maggard); Exh. 215 at 29:20 to 30:4.

7.7.3 Hydro Decommissioning: PG&E's Request for Hydro Decommissioning Accruals Should Be Deferred Until the Next GRC.

PG&E has not met its burden to show its proposed annual accruals for hydroelectric decommissioning are reasonable. Those accruals would be collected to decommission 13 small hydroelectric generating units the utility expects will be uneconomic to operate and relicense.[229] The accruals are intended to cover the cost of winding down the operation of the units, dismantle and remove them, and perform any necessary environmental restoration.[230]

PG&E has been forthright that it "is difficult to determine with certainty which hydroelectric projects would be decommissioned, when they would be decommissioned, and what the scope of the decommissioning would be."[231] For that reason, the utility used a high-level estimate of the total decommissioning costs it believes will be necessary, eventually arriving at a total cost of $242.7 million.[232] This sum is based on the estimated costs to decommission the 13 projects, weighted by PG&E's internal estimate of the likelihood that they will actually need to be decommissioned.[233] The result is PG&E's request for an annual accrual for decommissioning of $18.5 million in 2020-2022.[234]

The problem with PG&E's estimate is that the utility (1) has been required by FERC to sell the DeSabla-Centerville project, (2) has already been approved to sell the Deer Creek and Narrows #1 facilities, and (3) is in the process of selling Kern Canyon and Tule units.[235] As PG&E acknowledged in response to discovery and during cross examination, selling a hydro

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229 Exh. 215 at 32:7-9.

230 19 Tr. 2202:17-25 (PG&E – Maggard).

231 19 Tr. 2203:10-16 (PG&E – Maggard); Exh. 146 at 8-19:5-7.

232 19 Tr. 2203:10-16 (PG&E – Maggard); Exh. 146 at 8-23:4-11 and Table 8-10.

233 Exh. 146 at 8-18:1 to 8-24:8.

234 19 Tr. 2204:9-12 and 17-22 (PG&E – Maggard); Exh. 215 at Attachment RTB-2, pp. 52-53 (PG&E Data Response to Joint CCAs DR 11, Q9(b)).

235 *See* D.19-10-011 and D.19-10-010; 19 Tr. 2205:3 to 2208:5 (PG&E – Maggard).

asset removes any need for PG&E to decommission the projects because decommissioning becomes the responsibility of the new owner.[236] Thus, in *less than one year* since PG&E filed its testimony for assets with decommissioning dates far into the future, more than 33% of the projects either will not need to be, or are very unlikely to be, decommissioned.

Moreover, while PG&E forecasts it will take ten years to decommission a hydroelectric project, the expected decommissioning dates for these projects is far more than ten years in the future.[237] This means funds are being collected earlier than they need to be collected. With the added uncertainty over whether PG&E will decommission or sell projects, it makes far more sense to wait to accrue decommissioning funds until the projects that are within ten years of their decommissioning date.[238] Within that time frame, it should be clear whether PG&E intends to re-license a plant, given the significant time required for the FERC re-licensing process,[239] or sell it.

The record is clear that the likelihood of PG&E decommissioning these plants at all, let alone within the next ten years, is much lower than the utility has assumed. As PG&E witness Maggard admitted during cross examination, if she had been putting together the decommissioning estimate today, she would have removed sold assets from the calculation and lowered the accrual as a result.[240] She also noted that any funds PG&E might earn from a sale of a hydroelectric plant will be available to fund decommissioning from other hydro assets.[241]

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236 19 Tr. 2204:16 to 2205:2 (PG&E – Maggard); Exh. 215 at Attachment RTB-2, pp. 4-5 (PG&E Response to Joint CCAS DR 2, Q7(a)).
237 Exh. 215 at 33:11-18.
238 *Id.*
239 *Id.*
240 19 Tr. 2209:10-13 (PG&E – Maggard).
241 19 Tr. 2208:8-11 (PG&E – Maggard).

Since PG&E has just begun to start to sell these assets in earnest, the JCCAs recommend the Commission revisit this issue again in PG&E's next GRC. PG&E's arguments in rebuttal justifying collecting these funds now based on "intergenerational equity" are ill-placed in the context of decades-old, "forever assets," which have been enjoyed by literal generations of customers that never contributed to their decommissioning.[242] The interim three years between this GRC and the next will not allow an entire generation to avoid contributing to decommissioning, but it will allow some dust to settle and more information to come light regarding which projects are likely to be sold or decommissioned.

In the alternative, both Cal Advocates and the JCCAs have proposed lowering PG&E's accruals. JCCA witness Beach re-evaluated PG&E's estimated hydro de-commissioning costs using a consistent approach that remedies the problems identified above.[243] His process is illustrated in a flow chart in his testimony.[244] The result of that logic is a revised estimate of $95 million ($7.2 million per year) for a reasonable level of accruals for hydro decommissioning, instead of PG&E's proposed $243 million.[245] This would be 39% of PG&E's request.[246] Similarly, Cal Advocates proposed an annual accrual of $10 million.[247]

There is no risk to PG&E if, for some unexpected reason, these amounts prove to be too low. If the Commission sets the amount of the accrual too low to account for the actual decommissioning costs, PG&E will still be able to recover the actual decommissioning costs.[248] PG&E witness Maggard explained PG&E will update its estimates for decommissioning in each

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242 Exh. 71 at 8-6:1 to 8-7:10.
243 Exh. 215 at 33:22-28.
244 *Id.*
245 *Id.*
246 *Id.*
247 Exh. 163 at 16:1 to 20:2; 19 Tr. 2210:23-26 (PG&E – Maggard).
248 19 Tr. 2211:2-26 (PG&E – Maggard); Exh. 151 (PG&E Data Response to Joint CCAs DR 15, Q4).

rate case "as well as reflect any actual decommissioning costs that have been incurred and then adjust the accrual accordingly."[249] PG&E's rebuttal testimony makes much of the reverse being true, *i.e.*, if the $18 million per year amount is too high, the accruals can be adjusted downward at later date.[250] All other things being equal, however, and especially in light of the deep uncertainty surrounding the need to decommission these plants, the more prudent approach is to keep those funds in customers' pockets rather than PG&E's. PG&E has not met its burden in this case to show otherwise.

7.7.5 Solar and Fuel Cell Decommissioning: PG&E's Request for Solar Decommissioning Accruals Should Be Deferred Until the Next GRC.

The Commission should reject PG&E's proposed solar decommissioning costs outright and require the utility to make a modified proposal in its next GRC. The utility is far from meeting its burden to demonstrate the reasonableness of its astronomical solar decommissioning proposal. PG&E proposes to allocate funds to decommission its 152 MW of utility-owned solar generation facilities in this case, with decommissioning expenses totaling $100.5 million or about $6 million per year.[251] On a per project basis, this amount is **$400/kW**, which is ***over 10% greater than the original cost for these facilities.***[252]

The enormous amount stems from a number of factors. First, utility-scale solar decommissioning is a new practice, since solar is a "relatively new technology" and solar facilities are only now beginning to approach the end of their 20 to 30-year useful lives.[253] As PG&E witness Royall explained, "we know of no utility-scale solar facility that has been

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249 19 Tr. 2211:2-26 (PG&E – Maggard).
250 Exh. 71 at 8-6:1 to 8-7:10.
251 Exh. 146 at 8-29:8; 19 Tr. 2169:9-21.
252 Exh. 215 at 36:9-17; Exh. 71 at 5-25:14-16; 19 Tr. 2170:3-6 (PG&E – Royall).
253 19 Tr. 2170:7-18 (PG&E – Royall).

decommissioned in the United States."[254] As a result, the consultants PG&E utilized to construct the estimate, a company called TLG, had never performed any solar decommissioning studies before PG&E's study.[255]

In addition, PG&E's study assumed it would simply dispose of both the solar PV panels and the racking support structure without seriously considering other options. The solar panels themselves can be recycled and possibly sold for re-use even though their output is degraded.[256] It is particularly important to assume a salvage value given that PG&E assumes only a 20-year life for these projects.[257] At the industry-standard degradation rate of 0.5% per year, the panels may still produce 90% of their original output after 20 years.[258] This salvage value can substantially or completely offset the costs of decommissioning.[259]

Portions of the support structures also can be reused instead of being sold for scrap.[260] PG&E should have considered repowering these projects by keeping the existing racking in place at the site and installing new panels and inverters, which would eliminate much of the decommissioning costs.[261] In an environment of increasing RPS mandates, it is prudent for the utility to consider such an approach for sites already interconnected to the grid.[262]

Beyond these shortcomings, PG&E's own experience shows the unreasonableness of its $400/kW estimate. The only PG&E solar project to undergo decommissioning, a small PV plant in a rural part of Fresno County, cost *less than half* of PG&E's estimate to decommission at

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254 19 Tr. 2170:10-12 (PG&E – Royall).

255 19 Tr. 2171:2-6 (PG&E – Royall); Exh. 215 at Attachment RTB-2, pp. 31-32 (PG&E Data Response to Joint CCAs DR 6, Q11(d)).

256 Exh. 215 at 37:8-15.

257 *Id.*

258 *Id.* at 37:8-19.

259 *Id.* at 37:8-15.

260 *Id.*

261 *Id.* at 37:8-19.

262 *Id.*

approximately $180/kW.[263] Indeed, despite PG&E witness Royall's head-scratching assertion that it was unclear if economies of scale would decrease the $/kW costs of decommissioning a project,[264] one would expect the decommissioning of larger utility-scale projects to bring that $180/kW figure down. Moreover, virtually all of PG&E's solar plants are located on agricultural land in the Central Valley, which should simplify their removal.[265]

With some of these factors in mind, it is not surprising the studies and reports JCCA witness Beach cited establish decommissioning costs at a fraction of those suggested by PG&E, including $10/kW, $50/kW and $82/kW.[266] In rebuttal, P&GE suggested Mr. Beach did not provide sufficient, site-specific details to substantiate his costs were more reasonable.[267] However, establishing the reasonableness of a proposal is PG&E's burden in this case, not the JCCAs' burden.

Moreover, Mr. Breach also cited an April 2018 Electric Power Research Institute ("EPRI") study performed by Sargent & Lundy estimated the cost of decommissioning an 11 MW solar plant to be $83 per kW-AC, even without any value from recycling or reusing the panels.[268] PG&E simply did not respond to this study in its rebuttal testimony.

The record is clear that PG&E's own past costs, as well as industry estimates for decommissioning, show the utility's estimate is far from reasonable. The best approach, given the novelty of utility-scale solar decommissioning to date is to give PG&E more time to study and understand the issue and propose a more reasonable estimate in its next GRC.

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263 19 Tr. 2717:6-20 (PG&E – Royall); Exh. 152 (PG&E Data Response to Joint CCAs DR 18, Q01).

264 19 Tr. 2172:14-21 (PG&E – Royall).

265 Exh. 215 at 1-2; Exh. 152 (PG&E Data Response to Joint CCAs DR 18, Q1).

266 Exh. 215 at 37:15 to 38:18, n. 71 and 72.

267 Exh. 71 at 5-29:24 to 5-33:10.

268 *See PV Plant Decommissioning Salvage Value: Conceptual Cost Estimate*, EPRI (April 2018), *available at* https://www.epri.com/#/pages/summary/000000003002013116/?lang=en-US.

If the Commission disagrees with requiring PG&E to come back with a more reasonable estimate in its next GRC, it should dramatically reduce the annual accruals. As PG&E admitted in a discovery response, there is no risk to PG&E if the Commission chooses to adopt an amount that is at least half of the $100.5 million requested by PG&E, and the costs for decommissioning proved to be higher.[269] While PG&E witness Royall was unable to directly answer the question during cross examination,[270] witness Maggard explained how the Commission-approved practices for decommissioning allow PG&E to recover the actual decommissioning costs if the annual accruals are set too low.[271] PG&E will simply "reflect any actual decommissioning costs that have been incurred and then adjust the accrual accordingly."[272]

PG&E witness Royall made much of the reverse being true.[273] However, similar to PG&E's hydroelectric decommissioning proposal, all other things being equal, the more prudent approach is to keep those funds in customers' pockets rather than PG&E's. PG&E has not met its burden in this case to show otherwise.

8. CUSTOMER CARE

PG&E's Customer Care organization "drives the Company's customer strategy across all Lines of Business and delivers a broad range of services, products and support to residential, small and medium business ("SMB"), large commercial and industrial ("LCI"), and agricultural customers across PG&E's service area."[274] Customer Care therefore touches all customers, even though not all customers utilize Customer Care services in equal proportions.

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269 *See* Exh. 151 (PG&E Response to Joint CCAs DR 15, Q3).
270 19 Tr. 2176:3-15 (PG&E – Royall).
271 19 Tr. 2211:2-26 (PG&E – Maggard).
272 19 Tr. 2211:2-26 (PG&E – Maggard).
273 Exh. 71 at 5-29:24 to 5-33:10.
274 *See* Exh. 91 at 1-1:8-11

JCCAs do not address PG&E's overall revenue requirements presented in its testimony regarding Customer Care. However, JCCAs do take issue with how PG&E has allocated its Customer Care costs between bundled and unbundled customers. The process of allocating costs to various utility functions is also commonly referred to as "functionalization." The terms "allocate" and "functionalize" (and their derivations) have been used interchangeably throughout this proceeding and both refer to the assignment of a particular cost to a particular utility unbundled cost category ("UCC") such as gas distribution, electric distribution or electric generation.

While the recommendations provided below pertain specifically to Customer Care costs, issues of proper cost allocation will be increasingly important for all "common" costs as more and more customers take unbundled service. Because JCCAs were able to obtain utilization data for much of the Customer Care portion of PG&E's Customer Care services via discovery, our recommendations herein are specific to Customer Care costs. However, going forward it will be important to closely scrutinize all commonly allocated costs to reflect cost causation principles when services are not utilized equally among various types of customers.

8.1 Introduction and Policy: The Rise of Unbundling in California Electricity Markets Requires A Closer Scrutiny of How Costs Are Allocated to Properly Reflect How Bundled and Unbundled Customers Utilize Shared Services.

Typically costs that only benefit certain functions are directly assigned to those functions and are recovered via the appropriate portion of PG&E's rate. For example, costs recorded to major work category ("MWC") EY (Electric Meter Maintenance) are appropriately allocated 100 percent to PG&E's electric distribution function, because electric meters are part of the electric distribution system and are required for any customer, bundled or unbundled, that takes electric distribution service.[275] However, other costs, such as those related to the PG&E's call centers, are used by all customers – electric generation, electric distribution and gas distribution customers and are thus considered to be "common" costs, or those that are paid for by all utility customers.

For most Customer Care costs associated with programs and services made available to all electric and gas customers, PG&E generally allocates such costs based on the total proportions of electric to gas customers that it serves. Of PG&E's entire customer base, approximately 55 percent take electric service (either bundled or unbundled) and 45 percent take gas service.[276] Thus, PG&E uses a 55/45 allocator to assign many of its Customer Care costs to electric distribution and gas distribution customers, respectively. Under PG&E's allocation method, it does not assign any portion of its common Customer Care costs to the electric generation function.

Historically, this allocation practice was not problematic because roughly all electric customers received a similar level of electric service (*e.g.*, integrated or bundled power supply, transmission, distribution, and customer-related services). However, PG&E's customer base has rapidly and dramatically changed such that unbundled customers now outnumber bundled customers.[277] Based on PG&E's forecast, in 2019, Unbundled Electric Customers comprised 53% of PG&E's load share.[278] This reality represents a significant change from history where nearly all PG&E customers were bundled. Further, based on data provided by PG&E through discovery, it is evident that for many Customer Care programs and services, bundled electric

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[275] Exh. 93 at 4-8:3-5; 15 Tr. 1547:15 to 1548:6 (PG&E – Zenner).

[276] Exh. 93 at 2-5:21-24.

[277] Exh. 216 at Attachment JAM-2, p. 3 (PG&E Data Response to Alliance for Nuclear Responsibility DR 2, Q7).

[278] *See id.*

customers utilize such services more than unbundled electric customers, reflecting a change in how different types of electric customers utilize PG&E's system. This change requires a reassessment and change to PG&E's historical functionalization methodology to ensure that customers pay only the costs that are associated with the level of service they receive from PG&E.

As such, the Commission should require PG&E to change its allocation methodologies to properly and equitably allocate common costs not just between electric and gas customers, but between bundled electric, unbundled electric, and gas customers. If these cost allocation methodologies are not updated, costs will be recovered in an inequitable and discriminatory manner resulting in customers paying for services in a proportion that is not aligned with their utilization of such services.

This would result in a violation of California law, which forbids cost shifts between groups of departed and bundled customers.[279] If unbundled customers pay for services that they utilize less, then they are subsidizing other types of customers on PG&E's system. This also gives PG&E a competitive advantage over CCAs and other LSEs by allowing it to recover costs of serving bundled customer from unbundled customers. Similarly, if the costs of serving electric distribution customers are spread to gas customers, then gas customers would be unfairly subsidizing the electric utility function. For example, based on one of JCCA's data requests, PG&E recognized that some of its costs to implement new electric rate designs were being inappropriately split between gas and electric customers, even though gas customers did not benefit from the services at all.[280] As a result, PG&E made an errata to allocate 100% of the

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279 Cal. Pub. Util. Code § 366.2(a), (f).

280 Exh. 93 at 3-2:13-17; Exh. 216 at Attachment JAM-2, pp. 31-32 (PG&E Data Response to Joint CCAs DR 9, Q11); 15 Tr. 1529:6-11; 15 Tr. 1531:6-25 (PG&E – Bartman).

costs to electric distribution customers to better reflect cost causation principles.[281] While this change increases rates for CCA customers, JCCAs do not oppose this change because it better reflects the fact that gas customers don't utilize these services.[282]

As more and more customers are taking unbundled service, it is important that PG&E's costs are properly functionalized to better reflect the utilization and corresponding cost causation of various utility services. Unbundled customers now outnumber bundled customers on PG&E's system and are likely to continue to increase over time. In the past when all or most electric customers on PG&E's system were bundled, the current detail supporting PG&E's functionalization process was sufficient. However, in today's business environment, insufficiently detailed data historically relied upon by PG&E to allocate costs between electric and gas customers is not sufficient in equitably allocating costs to and recovery costs from bundled electric, unbundled electric, and gas customers. PG&E's cost allocation methodology must be adjusted to reflect utilization of its services and cost causation.

A. The Relative Utilization of a Particular Customer Care Service Should be Used to Directly Allocate Certain Common Customer Care Costs in this GRC.

Basing allocation on how customers utilize a particular service is a standard way to allocate common costs that PG&E regularly employs. For example, PG&E proposes to allocate helicopter costs using chargebacks to the UCC that uses the helicopter.[283] Further, while PG&E had originally had its locate and mark ("L&M") activities allocated 57/43 between electric and gas distribution, the Company ultimately agreed with JCCAs that the costs should be re-allocated

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281 Exh. 93 at 3-2:13-17; 15 Tr. 1531:21-27 (PG&E – Bartman).

282 15 Tr. 1532:15-17.

283 *See* Exh. 215 at Attachment RTB-2 pp. 1, 19 (PG&E Data Response to Joint CCAs DR 1, Q7(a) and DR 3, Q5(b)(i)). *See also* Exh. 80 at 9-10:12 to 9-11:8 (describing how the capital expenditures are allocated).

to reflect the fact that the majority of L&M activities (MWC DF) are associated with gas distribution assets.[284] It is important to note that while PG&E accepted JCCA's revised L&M allocation for now, it plans to more closely track L&M activities going forward to come up with an allocator that better reflects the utilization of that service.[285] In a number of other instances, PG&E made errata to its originally filed testimony to correct certain functionalization mistakes and to better reflect actual utilization of certain services.[286]

For a variety of Customer Care activities, PG&E proposes to use its 55/45 allocator that is merely reflective of the relative proportion of its electric and gas customers. However, PG&E possesses more detailed data, and has provided that data to JCCAs in discovery. The results of analyzing that data show that, on average, bundled electric customers utilize a number of PG&E's Customer Care services more frequently than unbundled electric customers. In some cases, the opposite is true, such as "Third Party Relations" in which unbundled customers utilize a service more than bundled customers. Based on the utilization data provided by PG&E, JCCA propose to more directly assign the costs of certain common Customer Care services to better reflect cost causation.

Consistent with PG&E's approach to allocating other costs of providing service, PG&E should allocate customer service-related costs within Customer Care based on actual customer utilization of the services PG&E provides. Consequently, if a particular service offering is provided 40% to bundled electric customers, 25% to unbundled electric customers, and 35% to gas customers, the rates each of those types of customers pay should be developed to recover

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[284] Exh. 15 at 6-7:26 to 6-8:12.

[285] 15 Tr. 1482:11-26 (PG&E – Klemm).

[286] Exh. 216 at 39:1 to 44:10. (The cumulative impacts of PG&E's errata are to increase Electric Generation $4.65 million, decrease Electric Distribution $11.473 million, and increase Gas Distribution $6.823 million. *See*, 44:8-10).

each customer type's pro rata utilization of that service offering. To produce cost recovery that reflects that utilization, PG&E cannot just allocate 40% of costs to Electric Generation, 25% to Electric Distribution, and 35% to Gas Distribution because bundled electric customers pay both Electric Generation and Electric Distribution rates, whereas unbundled electric customers pay only Electric Distribution rates. As such JCCAs proposed in our testimony to weight the allocation of customer service-related costs between PG&E's three utility functions such that the portion of costs allocated to Electric Generation when combined with the bundled customer's share of the Electric Distribution revenue requirement will produce rates paid by electric bundled and electric unbundled customers that reflect their pro rata utilization of each customer service-related program. PG&E in its rebuttal testimony did not rebut or object to this approach.

The allocators developed and proposed by the JCCAs reflect actual utilization of PG&E's programs and services. Taken together, the cumulative total of the refined allocation of costs for these specific programs can be used to allocate additional "common" costs PG&E currently proposes to allocate using the 55/45 allocator. The cumulative total allocations adjusted and proposed by the JCCAs are contained below:

					Proposed Allocation (%)			Proposed Allocation ($000)		
PGE 6 Ch	**GRC Cost Category**	**Department**	**Specific Program/Service**	**Total Cost (Expense)**	**Elec Gen**	**Elec Dist**	**Gas**	**Elec Gen**	**Elec Dist**	**Gas**
Ch 2	Customer Engagement	IV: Provide Account Services	Large Commercial, Industrial and Agricultural Customer Reps	$2,309	8%	47%	45%	$180	$1,088	$1,041
			Small and Medium Business Customer Reps	$5,045	7%	62%	31%	$347	$3,116	$1,581
			Division Leadership Teams	$4,883	15%	48%	37%	$715	$2,348	$1,819
			Customer Success	$2,302	-12%	72%	40%	($284)	$1,654	$931
			Third Party Relations	$1,794	-108%	184%	25%	($1,943)	$3,294	$444
		DK: Manage Customer Inquiries	Escalated Complaints	$928	50%	0%	50%	$462	$3	$463
Ch 5	Customer Care	Customer Service Offices		$19,268	11%	45%	45%	$2,069	$8,598	$8,601
Ch 4	Contact Centers			$63,942	18%	36%	46%	$11,725	$22,943	$29,274
	Total			**$100,471**				**$13,271**	**$43,045**	**$44,155**
			1. Adjusted Common Customer Care Cost Allocator					**13.21%**	**42.84%**	**43.95%**

Correcting PG&E's functional allocation factors to appropriately reflect cost of service differences for Customer Care between Bundled and Unbundled customers reduces the Electric Distribution revenue requirement by $12.22 million, increases Electric Generation by $13.27 million, and increases Gas Distribution by $1.05 million.[287]

8.2 Customer Engagement

In Chapter 2 of its Direct Testimony (Exhibit 91) PG&E explains that Customer Engagement provides many services and benefits to customers including offering customer representatives that provide account services and support to large commercial, industrial and agricultural customers and small and medium business customers, and other customer support, education and outreach activities.[288] Customer Engagement also handles escalated complaints

287 Exh. 216: 23, ln. 4-6.

288 Exh. 91: p. 2-1; ln. 6-26.

that come through call centers or customer service offices.[289] While these services are equally available to both bundled and unbundled customers, data provided by PG&E demonstrates that they are utilized by bundled customers in greater proportions.

8.2.1 Cost Allocation

PG&E asserts that Customer Engagement costs should be allocated based on its 55/45 customer count allocator and should not be further divided to reflect how bundled and unbundled service providers utilize these various services.[290] PG&E essentially argues that because the services provided by Customer Engagements are *equally available* to both bundled and unbundled customers, that the costs should be shared equally between them.[291] However this argument fails when one considers that large volumes of electricity are also *equally available* to any customer that chooses to utilize more electricity than their neighbors. Nevertheless, PG&E (and other utilities) only charges customers based on the actual amount of energy that they use – not the amount of energy that is available to them. This makes sense in that customers that use more electricity cause more generation costs than customers that use less. The same is also true for Customer Engagement (and other shared) services – customers that use the services more drive cause more of the costs. PG&E acknowledged at hearing that it does not argue in its rebuttal testimony that bundled and unbundled customers *utilize* Customer Engagement services in equal proportions.[292]

In discovery, PG&E provided actual utilization numbers for the Customer Engagement activities by both bundled and unbundled customers, which is included as Table 3 of Mr. Mancinelli and Mr. Reger's Direct Testimony. The relevant portions of Table 3, regarding

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289 15 Tr. 1495:9-15.
290 Exh. 93 at 2-5:16-29.
291 15 Tr. 1517: 7-16 (PG&E – Brown).
292 15 Tr. 1518: 18-24 (PG&E – Brown).

Customer Engagement, are reproduced below.

Customer Engagement Usage by Customer Type[293]

PGE 6 WP	Chapter	MWC	Department	Specific Program/Service	Count of Customers Receiving Service (by Type)			Proportion of Customers Receiving Service (by Type)		
					Bundled Elec.	Unbundled Elec.	Gas	Bundled Elec.	Unbundled Elec.	Gas
Ch 2	Customer Engagement	IV: Provide Account Services	Business Energy Solutions	Large Commercial, Industrial and Agricultural Customer Reps[1]	1,827	1,524	2,751	29.9%	25.0%	45.1%
				Small and Medium Business Customer Reps[1]	169,509	154,496	147,923	35.9%	32.7%	31.3%
			Local Cust. Experience	Division Leadership Teams[2]	19	13	19	37.3%	25.5%	37.3%
				Customer Success[1]	894	876	1,203	30.1%	29.5%	40.5%
				Third Party Relations[1]	0	1,272,328	418,000	0.0%	75.3%	24.7%
		Manage Customer Inquiries		Escalated Complaints[1]	2,678	7	2,678	49.9%	0.1%	49.9%

The above utilization data for various different services are undisputed by PG&E[294] and demonstrate that for certain functions, such as managing escalated complaints and third-party relations, bundled and unbundled customers utilize these services in vastly disproportionate ways. While PG&E does not challenge the service utilization data contained in Table 3, it did testify at hearing that utilization of these services between bundled and unbundled customers "feels about even."[295]

With regard to escalated complaints, Table 3 demonstrates that the vast majority of this service is utilized by bundled customers. This makes logical sense when one considers that some escalated complaints are referred to an unbundled customer's CCA for ultimate resolution.[296] PG&E acknowledges that prior to the introduction of CCAs, all escalated complaints were handled by PG&E itself; whereas now, a portion of such complaints are referred to the CCAs.[297] In other words, PG&E's escalated complaints department now handles fewer complaints than it would if CCAs did not exist.

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293 Exh. 216 at 17:5-6 (*citing,* PG&E Data Response to Joint CCAs DR 13, Q6, included in Attachment JAM-2, pp. 47-49).

294 15 Tr. 1506:8-12 (PG&E – Brown); Exh. 100 (PG&E Data Response to Joint CCAs DR 15, Q7).

295 15 Tr. 1519; 26-28 (PG&E – Brown).

296 Exh. 102 (PG&E Data Response to Joint CCAs DR 15, Q9).

297 15 Tr. 1512:27 to 1513:10 (PG&E – Brown).

Similar to escalated complaints, third-party relations services listed in Table 3 show a utilization rate similarly skewed towards unbundled electric customers over bundled electric customers. This utilization data supports allocating more costs to the CCAs, and cost causation principles dictate that the program costs associated with these third-party relations services should be recovered from the unbundled electric and gas customers who utilize such services.

Using the utilization data in Table 3, JCCA witnesses Mr. Mancinelli and Mr. Reger derived allocators based on the actual utilization of Customer Engagement services and programs to re-allocate such costs to better reflect the services provided to various customer types.[298] For Customer Engagement costs JCCAs propose to directly allocate PG&E's Customer Engagement Activities resulting in a *decrease* of $0.52 million to electric generation, an increase of $2.01-million to electric distribution, and a decrease of $1.48 million to gas. These adjustments to Customer Engagement taken alone are not a benefit to CCA or other unbundled customers, but better reflect cost causation. The disparity in utilization between bundled and unbundled customers is even more pronounced with regard to other Customer Care services described in the following sections.

298 Exh. 216 at 23:1, Table 7.

8.4 Contact Centers

Contact Centers include call centers, which are also capable of receiving and responding to email inquiries and represent the vast majority of the expenses contained within Customer Care at almost $64 million.[299] Because these are the highest costs contained within Customer Care the way in which they are allocated also has the greatest impact of all the Customer Care costs on the revenue requirements for each UCC.[300]

8.4.1 Cost Allocation

PG&E's Call Centers handle substantially more calls and email inquiries from bundled electric customers than unbundled electric customers; yet, PG&E functionalizes its Contact Center costs as if bundled and unbundled Electric Customers receive the same level of service.[301] This is inconsistent with the appropriate, fair, and equitable cost allocation to the various functions and recovery of such costs from the utility's customers. Similar to their arguments discussed in the Customer Engagement section above, PG&E maintains that it is appropriate for bundled electric and unbundled electric customers to share equally in the Contact Center costs because the Contact Center services are equally available to both types of electric customers alike.[302] As noted above, this argument fails for the simple reason that just because something (electricity or otherwise) may be *available* to customers, does not mean that they have to use it. Indeed, in most free markets, customers only pay for what they use. Imagine the outrage if a grocery store were to charge all customers for the apples on the shelf, simply because they are equally available for all customers to purchase. Similar to the Customer Engagement costs,

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[299] Exh. 91 at 4-1:19-20.
[300] 15 Tr. 1547:1-10 (PG&E – Zenner).
[301] Exh. 216 at 17:5-6, Table 3 (*citing,* Exhibit 216 at Attachment JAM-2, pp. 37-40 (PG&E Data Response to Joint CCAs DR 10, Q6 and Q7).
[302] Exh. 93 at 4-7:13-19; 15 Tr. 1553:25 to 1554:3 (PG&E – Zenner).

PG&E does not argue that bundled and unbundled customer utilize Contact Centers in equal proportions, and the data PG&E itself keeps proves that bundled electric customers utilize contact centers far more frequently than unbundled electric customers, and thus drive substantially more of the costs PG&E incurs in maintaining the contact centers.

In fact, via several discovery responses, PG&E provided utilization data for the Contact Centers by both bundled electric and unbundled electric customers. Those figures are included in Table 3 of Mr. Mancinelli and Mr. Reger's Direct Testimony and the relevant portions, regarding Contact Centers, are reproduced below.

Contact Center Usage by Customer Type[303]

PGE 6 WP	Chapter	MWC	Department	Specific Program/Service	Count of Customers Receiving Service (by Type)			Proportion of Customers Receiving Service (by Type)		
					Bundled Elec.	Unbundled Elec.	Gas	Bundled Elec.	Unbundled Elec.	Gas
Ch 4	Contact Centers			Customer Calls/Emails[3]	3,828,427	1,425,637	4,436,624	39.5%	14.7%	45.8%

In response to JCCA discovery request JCCAs_015-Q10, PG&E criticized some of the utilization numbers for Contact Centers provided above and in Table 3 of Mr. Mancinelli and Mr. Reger's testimony and provided two reasons for their dispute.[304] However, upon closer examination at hearing it was revealed that each of their criticisms should be dismissed as inconsequential.

First, PG&E points out that JCCAs_015-Q10 was confusing because it asked whether PG&E disputes the "actual Customer Care customer counts" contained in Table 3 when in fact what PG&E provided (and what JCCAs had originally requested) was the total number of calls, email and escalated complaints, not the total number of customers that made those calls, emails

303 Exh. 216 at 17:5-6 (*citing,* Exhibit 216 at Attachment JAM-2, pp. 37-40 (PG&E Data Response to Joint CCAs DR 10, Q6 and Q7).
304 Exh. 103 (PG&E Data Response to Joint CCAs DR 15, Q10).

or escalated a complaint.[305] JCCAs concede that this question was confusing, but nevertheless agrees with PG&E that the total numbers of contacts (via email, call or other) are a better indication of cost causation than the number of customers that contacted a Contact Center.[306]

Second, PG&E claims that the numbers of calls, emails and escalated complaints in JCCA's Table 3 did not match the numbers provided in response to JCCA_013-Q6, Table 2.[307] Mr. Mancinelli and Mr. Reger's testimony did not use the numbers provided in JCCA_013-Q6 because the numbers provided in JCCA_013-Q6 were from 2017 and more recent numbers were available. Instead, in an attempt to use more recent data, JCCA's utilized call and email counts from 2018 provided by PG&E in JCCA Joint CCAs DR10, Q6 and Joint CCAs DR 10, Q7 supp. 1.[308] When numbers PG&E provided from these two DRs are added together, the result is the values contained in JCCA's Table 3 Contact Center calls and email figures.[309]

PG&E also notes that JCCAs failed to include escalated complaint numbers that came through Contact Centers but also acknowledged at hearing that these figures were very small in comparisons to the much larger volumes of calls and emails.[310] Because the omitted numbers were comparatively very small (522 versus over 3 million), their omissions do not influence JCCA's allocation recommendations. JCCAs stand by the numbers in Table 3 of Mr. Mancinelli and Mr. Reger's Testimony, which demonstrate that bundled electric customers utilize Contact Centers at a rate more than double with which unbundled electric customers utilize them.[311]

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305 Exh. 103 at. 1 (PG&E Data Response to Joint CCAs DR 15, Q10(a)(i)); Tr. 1561:19 to 1562:12 (PG&E – Zenner).

306 15 Tr. 1559:17-24; 1564:3-11 (PG&E – Zenner).

307 Exh. 103, p. 2 (PG&E Data Response to Joint CCAs DR 15, Q10(a)(i)(2)).

308 Exh. 216 at 17:8-9 (*citing*, Exh. 216, Attachment JAM-2 at pp. 37-40).

309 Bundled electric customers: 3,707,944 calls and 120,483 emails; unbundled electric customers: 1,380,771 calls and 44,866 emails; and gas customers: 4,297,000 calls and 139,624 emails.

310 15 Tr. 1570:2-10 (PG&E – Zenner).

311 3,828,427 calls and emails from bundled customers versus 1,425,637 from unbundled customers.

JCCA's primary rationale for re-allocating Contact Center costs is driven by the data provided by PG&E and included in Table 3 of Mr. Mancinelli and Mr. Reger's Testimony. However, JCCAs also pointed out that the lower utilization rates by unbundled customers makes logical sense when one considers that CCAs also have call centers that handle customer inquiries, which should relieve some of the burden on PG&E's Contact Centers.

In its Rebuttal Testimony, PG&E asserts that it saw an increase in total customer calls from 2015-2017 over a period when CCA customer counts increased. PG&E claims that this is not what you would expect to see if unbundled electric customers use Contact Centers less frequently than bundled electric customers.[312] However PG&E's data, which it presents in Tables 4-3 and 4-4 of its Rebuttal Testimony,[313] is flawed for two key reasons: the dates it uses for showing an increase in the number of calls to contact centers (2015 to 2017) and for CCA customer counts (2015 to 2018) are inconsistent; and PG&E's analysis fails to account for a general increase in the total number of customers on PG&E's system during the same time period.

First, as PG&E acknowledged on the stand, Table 4-3, which shows an increase in the total number of calls handled by contact centers between 2015 and 2017, fails to account for the additional half a million (approximately) total new customers that were added to PG&E's system during that same time period.[314] Second, the comparison that PG&E makes between its Tables 4-3 and 4-4 is not an apples to apples comparison because PG&E presents the total number of calls handled in 2015 and 2017 (Table 4-3) and compares that to the total number of CCA

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[312] Exh. 93 at 4-9:1-14.
[313] *Id.* at 4-9:14 to 4-10:1.
[314] Exh. 108 at 2 (PG&E Data Response to Joint CCAs DR 15, Q18); 15 Tr. 1605:1 to 1606:2 (PG&E – Zenner).

customers between 205 and 2018 (Table 4-4).[315] Finally, in incorporating the growth in total customer counts on the PG&E system into the analysis by looking at the total calls per customer, as opposed to just total call volume, it is clear that calls per customer actually *declined* during the 2015-2018 period.[316]

In discovery, PG&E attempted to demonstrate that calls per unbundled customer were higher than calls per bundled customer, however once again PG&E used mis-matched data to make its comparison.[317] As acknowledged at hearing, PG&E's calls per customer analysis used bundled customer data from a single month (January) and Unbundled customer data from a different single month (April), rather than relying on matched longer-term data summarized over a full year or longer.[318] This mis-match is particularly concerning given PG&E's admission at hearing that the Contact Center's "world changes on a weekly, monthly basis in terms of how calls come in. Weather events and different things. It's constantly evolving."[319] As such, the Commission should ascribe no weight to PG&E's incorrect and misleading assertions that customer calls have gone up since the proliferation of CCAs because it is simply not accurate.

Indeed, PG&E acknowledges that it now refers customers to CCAs call centers for a myriad of issues, which in the absence of CCAs, PG&E would have handled itself.[320] While PG&E does not track all of the instances when it refers a customer to a CCA for resolution of a Contact Center inquiry, it does admit that in 2018 its automated phone system referred 25,092

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315 Exh. 93, at 4-9:14 to 4-10:1.

316 Exh. 219, labeled row (6), column (o), showing a 2015 – 2018 calls per customer decline of 1.66%.

317 *See*, Exh. 103 at 2-3 (PG&E Data Response to Joint CCAs DR 15, Q10); 15 Tr. 1578:21 to 1579:5 (PG&E – Zenner).

318 *Id.*

319 15 Tr. 1605:27 to 1606:2 (PG&E – Zenner).

320 Exh. 104 at 2-3 (PG&E Data Response to Joint CCAs DR 15, Q11); 15 Tr. 1584:20 to 1585:7 (PG&E – Zenner).

calls to CCAs for resolution. That is at least 25,092 customer calls that PG&E Customer Contact representatives failed to resolve.

Because PG&E is unable to appropriately refute JCCAs' utilization figures presented in Table 3 of Mr. Mancinelli and Mr. Reger's Testimony, and because utilization of services is an appropriate way to allocate costs, and because JCCAs have demonstrated that total calls per customer have declined between 2015-2018 while CCA customer counts have increased, the Commission should adopt the JCCA's proposed adjustment to Contact Center cost allocations. For Contact Center costs, JCCAs propose that PG&E's requested revenue requirement of approximately $63 million be allocated 18% to electric generation, 36% to electric distribution and 46% to gas distribution to better reflect utilization and corresponding cost causation.[321] This results in an increase of $11.7 million to electric generation, a decrease of $12.2 million to electric distribution and an increase of $.5 million to gas distribution.[322] As noted above, PG&E did not challenge JCCAs mathematical approach.

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321 Exh. 216 at 23:1-2, Table 7.

322 *Id.*

8.5 Customer Service Offices

Table 3 of Mr. Mancinelli and Mr. Reger's Testimony demonstrates that bundled customers utilize PG&E's Customer Service Offices almost twice as much as unbundled customers.[323] Those figures are included in Table 3 of Mr. Mancinelli and Mr. Reger's Direct Testimony and the relevant portions, regarding Customer Service Offices, are reproduced below.

Customer Service Offices Usage by Customer Type[324]

PGE 6 WP	Chapter	MWC	Department	Specific Program/Service	Count of Customers Receiving Service (by Type)			Proportion of Customers Receiving Service (by Type)		
					Bundled Elec.	Unbundled Elec.	Gas	Bundled Elec.	Unbundled Elec.	Gas
Ch 5	Customer Care	Customer Service Offices		Locations/Customers Served[4]	394,888	194,927	475,580	37.1%	18.3%	44.6%

PG&E did not dispute these figures, which were derived from its Data Response to Joint CCAs DR 10, Q11 attachment 1 and attachment 2.[325] As such, the Commission should adopt JCCA's recommendation to directly allocate PG&E proposed $19.2 million revenue requirement 11% to electric generation, 45% to electric distribution and 45% to gas distribution. This results in an increase of $2.01 million to electric generation, a decrease of $2 million to electric distribution and a decrease of $.07 million to gas distribution.[326] As noted above, PG&E did not challenge JCCAs mathematical approach.

8.8 Regulatory Policy and Compliance

Because PG&E lacks detailed utilization data for some of its Customer Care services, the Commission should a) require PG&E to use JCCA's Adjusted Common Customer Care Cost Allocator when there is insufficient data regarding utilization of a particular Customer Care service; b) require PG&E to track and report on how common Customer Care services are

[323] Exh. 216 at 17:5-6, Table 3.

[324] *Id.* at 17:5-6 (*citing,* Exhibit 216 at Attachment JAM-2, pp. 51-53 (PG&E Data Response to Joint CCAs DR 10, Q11, Attachment 1 and Attachment 2)).

[325] Exh. 216 at Attachment JAM-2, pp. 51-53 (PG&E Data Response to Joint CCAs DR 10, Q11, Attachment 1 and Attachment 2)).

[326] *Id.*

utilized going forward; and c) require PG&E to present its allocations of shared costs more transparently in future GRCs.

A. Where there is Insufficient Data regarding the Utilization of a Particular Customer Care Service, The Commission Should Require PG&E to Use JCCA's Adjusted Common Customer Care Cost Allocator.

As discussed above, PG&E uses a count of Electric Distribution and Gas Distribution customers (55% and 45%, respectively) to allocate many costs related to customer service the utility deems to be equally available to all of its customers. As the discussion above has shown, PG&E makes this decision to use the 55/45 allocator even when more detailed and granular utilization data is available that would inform a more nuanced allocator that better tracks cost causation. For costs associated with certain programs and services pertaining to Customer Engagement, Contact Centers and Customer Service Offices and for which PG&E has provided detailed utilization data, JCCAs recommend that the Commission directly allocate such costs based on that utilization data, as described above. However, it is reasonable to assume that there are additional costs within Customer Care that PG&E has used the blanket 55/45 allocator when a more detailed cost allocation would be more equitable and appropriate.

While PG&E did not provide sufficiently detailed program- or service-related cost data to specifically identify all costs within Customer Care currently allocated using the 55/45 allocator, one can surmise a reasonable approximation in analyzing the build-up of PG&E's Labor Allocator, provided to the JCCAs in response to discovery.[327] In reviewing PG&E's response, JCCAs determined that there are labor costs in customer-service related FERC Accounts 900-912 totaling $266,168,175. Of those labor costs, $154,857,234 or 58.2% are functionalized

[327] *See* Exh. 216 at Attachment JAM-2, pp.42-43 (PG&E Data Response to Joint CCAs DR 12, Q1 and Attachment 1).

using PG&E's "common" (55/45) cost allocator.[328] JCCAs used this 58.2% percentage and applied it to the total Customer Care dollar amount of $318.9 million to produce an estimate of $185.6 million within Customer Care reasonable assumed to be "common," or available to all customers and functionalized using the 55/45 allocator.[329]

Absent more detailed utilization data for such remaining "common" Customer Care costs, JCCAs recommend that the Commission compel PG&E to use the cumulative impacts of the allocation factor adjustments above to inform a more equitable allocation of Customer Care costs. This "composite allocator" is contained in Table 7 of Mr. Mancinelli and Mr. Reger's testimony and allocates remaining "common" costs within Customer Care 13.21% to Electric Generation, 42.84% to Electric Distribution, and 43.95% to Gas.[330] The Commission should require PG&E to allocate $185.6 million of its Customer Care expenses in this manner. Though actual utilization data is not available, for the time being, the JCCAs assume PG&E's current allocation of the remaining ($133.3 million) Customer Care expenses are reasonable. Based on this total, PG&E should allocate Customer Care costs as follows: $35.476 million to Electric Generation, $172.385 million to Electric Distribution, and $111.076 million to Gas Distribution.[331]

PG&E did not provide any rebuttal testimony or evidence to challenge JCCAs methodology to come up with its Adjusted Common Customer Care Cost Allocator. While PG&E did challenge the notion that bundled and unbundled customers should pay different Customer Care rates due to the fact that such services are equally available to both sets of

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[328] Exh. 216 at 25:8-14.
[329] *Id.* at 25:17-19
[330] *Id.* at 23:1-2, Table 7; *see also,* 25:15 to 27:8.
[331] *Id.* at 28:3-6.

customers, they did not challenge JCCA's calculations or claim that they were in any way deficient. As such, PG&E has not met its burden of proof to challenge JCCA's recommendation.

B. The Commission Should Require PG&E to Track and Report on How Common Customer Care Services are Utilized Going Forward.

The JCCA's Adjusted Common Customer Care Cost Allocator developed and proposed to be used to allocate "common" Customer Care costs reflects actual utilization of customer service-related programs, and is a more equitable cost allocation methodology than PG&E's proposed 55/45 allocator. Going forward in future GRC proceedings, PG&E should more carefully track utilization of programs and services provided under Customer Care so that it can more precisely allocates such costs in future GRCs. It is clear based on PG&E's responses to discovery that the utility already keeps voluminous and detailed data on many of these programs and services, it has just not relied on that data to more equitably functionalize costs. PG&E's reasons for not leveraging such available data are not explained in its Application nor its Rebuttal Testimony. In Rebuttal Testimony, PG&E claims that increasing data collection and detail to track customer inquiries as electric generation-related versus electric delivery-related would be unduly burdensome.[332] However, in discovery, PG&E admitted that it "does not have any formal reports or studies on the level of difficulty required to track customer types by call."[333]

Nevertheless, PG&E provided a "back of the envelope" estimate that to accomplish this type of tracking for the Contact Centers alone, would cost about $656,000.[334] Assuming this is roughly in the ballpark and given that PG&E's Contact Center costs are over $63 Million per

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[332] Exh. 91 at 4-8:9-11.

[333] Exh. 105 at 1 (PG&E Data Response to Joint CCAs DR 15, Q12Rev01).

[334] *Id.* at 2 (PG&E Data Response to Joint CCAs DR 15, Q12Rev01); 15 Tr. 1587:14 to 1589:2 (PG&E – Zenner).

year, tracking customer inquiries as electric generation-related versus electric delivery-related would cost roughly 1% of the total requested amount.[335] This hardly seems "unduly burdensome" from a cost perspective, especially when considering that JCCAs are proposing an allocation adjustment on Call centers equal to about $12.2 million based on utilization numbers. Further, PG&E already tracks call types on a myriad of other topics, demonstrating that call tracking in and of itself is a common practice and not unduly burdensome.[336] As such, the Commission should order PG&E to more carefully track the utilization of tis various Customer Care services between bundled and bundled customers and to use those numbers to propose proper functionalization methods, as detailed in the following section.

C. The Commission Should Require PG&E to present its Allocations of Shared Costs More Transparently in Future GRCs.

As noted above, California Law forbids cost shifts between groups of departed and bundled customers[337] and explicitly states that "[t]he implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation."[338] However, because PG&E's functionalization process is opaque, it is not possible for the Commission, or other interested parties such as the JCCAs to ensure that there is no improper subsidization.

With the exception of data provided by PG&E on Customer Care programming provided through discovery, and discussed in Section 8.1.A above, the information provided by PG&E on its cost functionalization process was not sufficient such that JCCA's expert witnesses could

335 15 Tr. 1590:9-14 (PG&E – Zenner).
336 Exh. 106 (PG&E Data Response to Joint CCAs DR 15, Q13); 15 Tr. 1591:19-24.
337 Cal. Pub. Util. Code § 366.2(a), (f).
338 Cal. Pub. Util. Code § 366.2(a)(4).

readily understand how various types of costs were assigned to utility functions.[339] Generally the information provided by PG&E was insufficient to readily audit the decisions made to allocate PG&E's costs among electric generation, electric distribution, and gas distribution.[340] While PG&E was willing to meet with JCCAs to answer questions on the opacity of its application, PG&E's initial testimony lacked detail to outline how costs were functionalized.[341]

This is primarily because PG&E's cost mapping is performed entirely within PG&E's Systems Application Products ("SAP") financial systems, which PG&E deemed proprietary and thus declined to share.[342] PG&E uses the term "Cost Model" to describe the methodology by which PG&E gathers and assigns costs, such as certain overhead costs, to its processes or activities.[343] The Cost Model, which is used to assign costs to various utility processes and/or activities, is an integral part of the SAP enterprise accounting system and, thus, was also not available in Excel format.[344] While the RO [results of operations] model is Excel-based and was provided for our review, it was provided to JCCA's witnesses as over twenty Excel files with a voluminous User's Reference Guide, none of which particularly focused on explaining the process for functionalizing PG&E's costs.[345] In fact, most if not all decisions on the functionalization of granular cost detail was completed up-stream from the RO model. This makes it impossible to audit the utility's functionalization process beyond reviewing a summary of the final results in the RO model for reasonableness, without access to the underlying supporting detail, made unavailable because of the proprietary nature of the SAP model.

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339 Exh. 216 at 44:12 to 45:5.
340 *Id.*
341 *Id.*
342 *Id.* at 45:6-14.
343 *Id.*
344 *Id.*
345 *Id.*

Further, PG&E did not provide O&M expense functionalization information in its testimony or elsewhere that was sufficient to understand its functionalization rationalization.[346] In PG&E-10 (Exh. 80), PG&E addresses how the O&M Labor Allocator was used to unbundle A&G expenses and depreciation expenses for residual general/common plant.[347] Beyond this instance, however, PG&E presented little information that could easily be used to understand how various types of costs were assigned to UCCs/utility functions.[348] In PG&E-10 (Exh. 80), Chapters 3 through 7, the amount of O&M expenses by MWC mapped to individual FERC accounts is shown, but not how they were assigned to UCCs/utility functions.[349] Also, in general, PG&E provided no explanation regarding the basis for mapping MWCs to FERC accounts.[350] After studying Chapters 3 through 7 in PG&E-10 (Exh. 80), JCCAs were able to understand how these O&M expenses were booked by FERC account, with the exception of costs for customer accounts and customer services.[351] These customer accounts and services were mapped to functions as shown in Exhibit PG&E-10 (Exh. 80), Tables 16-1 and 16-2, but no information was provided on how they were mapped to UCCs (utility functions) as shown in PG&E-10 (Exh. 80), Appendix A, Tables A-22 through A-24.[352]

However, information from PG&E's accounting system could be used to develop data that would better support the utility's cost functionalization decision making.[353] In light of the massive amount of unbundling that is occurring in PG&E's service territory and the legal requirements to ensure that unbundled customer do not subsidize bundled customers, the

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346 *Id.* at 45:15 to 46:2
347 *Id.*
348 *Id.*
349 *Id.*
350 *Id.*
351 *Id.*
352 *Id.*
353 *Id.* at 46:3-25.

Commission should require PG&E to prepare the detail necessary to examine these costs and ensure their proper treatment in the unbundling and functionalization process.[354] Specifically, the Commission should require PG&E to provide extensive detail on the reasoning it employed in functionalizing its costs in future GRC Phase I testimonies.[355] PG&E should be required to identify in each Chapter of their testimonies and by subsequent MWC, how those costs were ultimately unbundled to its various utility functions and provide explanations and other evidence, as appropriate, to support its proposed cost unbundling.[356] Further, summary tables should be developed and made available to show how detailed program-level costs are allocated to the utility's UCCs, so on can trace a system-wide functionalized revenue requirement all the way back to individual cost entries the cumulative total of which represent the utility's functionalized revenue requirement.

11. ADMINISTRATIVE AND GENERAL EXPENSES

11.3 Risk, Audit and Insurance Departments

11.3.3 General Liability Insurance and Miscellaneous (Utility): The Commission Should Not Modify PG&E's Long-Standing Practice to Functionalize Insurance Costs Across All Lines of Business.

Both Cal Advocates and CUE recommend breaking from PG&E's long-standing practice of functionalizing insurance costs across all lines of business. Specifically, Cal Advocates recommends that approximately $300 million of incremental costs from excess liability insurance expense be allocated only to the electric distribution and electric transmission functions to reflect the increased number of wildfires over the past several years.[357] It derives this $300 million figure by comparing a five-year average of what these expenses were from

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[354] *Id.*
[355] *Id.*
[356] *Id.*
[357] Exh. 174 at 15:14-18.

2013-2017 to what PG&E forecasts it will need for 2020.[358] CUE agrees that a substantial portion of these expenses should be allocated solely to electric distribution and electric transmission to reflect an increase in these costs due to wildfires, and proposes an alternate trendline analysis to estimate that anywhere between $238 million and $254 million should be reallocated.[359]

The JCCAs oppose these proposals for reallocation in light of the fact that (1) PG&E continues to sustain significant risk across all its lines of business—which this insurance covers, (2) neither Cal Advocates nor CUE is able to identify with a reasonable degree of certainty the amount of the cost increase attributable to wildfires, and (3) administration of either of these proposed alternatives would be untenable going forward, especially given that neither method can readily account for a situation in which multiple variables are causing an increase in costs.

PG&E's excess liability insurance is a "single tower coverage policy," that "is general in nature, and is not limited to or directed at any specific utility function[,]" and that protects "against third-party claims to all lines of business."[360] Both Cal Advocates' and CUE's witnesses acknowledge that payments on liability claims related to liabilities caused by PG&E's gas storage facilities, its gas pipelines, or its generation facilities would come out of this same pool of insurance.[361] Given this coverage, these costs are classified as administrative and general expenses and functionalized as common costs.[362]

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358 21 Tr. 2352:6-12 (Cal Advocates – Weaver).

359 Exh. 62 at 6:6-10 (noting that CUE does not have a position as to which analysis—as between its analysis and Cal Advocates'—yields a more exact number, but that both analyses show that a large amount should be reallocated to electric distribution and electric transmission).

360 Exh. 159 at 3-32:7-13.

361 13 Tr. 1332:19-27 (CUE – Earle); 21 Tr. 2353:18-24 (Cal Advocates – Weaver).

362 Exh. 159 at 3-32:2-3; 13 Tr. 1332:28 to 1333:5 (CUE – Earle); 21 Tr. 2353:25 to 2354:12 (Cal Advocates – Weaver).

The functionalization of these costs across all lines of business reflects a long-standing practice that has remained consistent through disasters caused by or related to various lines of business. As JCCA witness Beach explained, "[t]he last decade in the energy industry in California has demonstrated that the state's energy utilities face significant safety risks and liabilities across all of their lines of business:"[363]

- In 2010, a PG&E local transmission pipeline in San Bruno, California, exploded, destroying a residential neighborhood and killing 8 people.[364]

- In 2015, the major leak at Southern California Gas Company's Aliso Canyon gas storage field exposed the risks of gas storage operations, including significant evacuations and health impacts in a residential neighborhood.[365]

- PG&E faces ongoing risks, and incurs insurance costs, associated with Diablo Canyon, with its gas-fired plants, and with the dams and water conveyance infrastructure for its extensive hydro system.[366]

- The problems with the spillways at the Oroville Dam in the winter of 2016-2017 illustrate the potential risks and liabilities of large hydro facilities.[367]

However, the Commission did not, for instance, attempt to protect electric ratepayers from any past increases in insurance premiums that may have been driven by the natural gas system risks exposed by the San Bruno and Aliso Canyon incidents in 2010 and 2015.[368]

Rather, in light of the significant risks across all lines of business, PG&E witness Yuen explains:

> In the past, the Commission has not sought to re-allocate the cost of insurance where premiums may have been affected by industry risks related to other lines of business such as Gas Transmission and Storage or hydroelectric activities for the purpose of assigning a higher percentage of the cost to those customer groups. Rather, the cost of insurance continued to be allocated as a common cost. The Commission should not choose to

363 Exh. 215 at 41:20-22.
364 *Id.*at 41:22-23.
365 *Id.*at 41:23-26.
366 *Id.*at 41:26 to 42:1.
367 *Id.*at 42:1-3.
368 *Id.*at 42:8-11.

> revise the allocation now, simply because premiums are currently being affected by heightened wildfire risk.[369]

Cal Advocates' and CUE's witnesses admitted during cross examination that they were unfamiliar with whether PG&E has, in the past, reallocated insurance costs to a particular line of business in reaction to events exposing industry risks related to that particular line of business.[370]

Not only are these alternative cost allocation proposals inconsistent with the fact that this insurance covers substantial and present risks across all lines of business, but they also both fail to identify with a reasonable degree of certainty the amount of the cost increase attributable to wildfires. Cal Advocates' position relies entirely on three excerpts in PG&E's testimony where the utility generally states that the increase in PG&E's liability insurance expense is largely due to increased wildfire risks.[371] The agency did not perform or review any other analyses that explain what is driving the increase in excess liability insurance premiums.[372] Moreover, while PG&E suggests wildfires are a major cause of its increased insurance expenses, it also clarifies in rebuttal testimony that, in the world of insurance pricing, specific and identifiable portions of increases in insurance premiums cannot be attributed to specific, individual events or factors.[373] The utility, therefore, is not claiming to know definitively what combination of factors is contributing to this recent increase, and the degree to which each such factor impacts the overall increase.

Similarly, CUE relies on PG&E's general statements on the impact of increased wildfire risk on insurance expenses[374] as the basis for its trendline analysis estimate. This analysis

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369 Exh. 72 at 7-3:6-13.
370 13 Tr. 1333:6-22 (CUE – Earle); 21 Tr. 2354:13-25 (Cal Advocates – Weaver).
371 21 Tr. 2355:4-23.
372 21 Tr. 2355:24 to 2356:17.
373 Exh. 159 at 3-9:16-20.
374 Exh. 62 at 4:3-5.

effectively assumes, based on this general testimony, that one hundred percent of the increase in insurance expenses above the trendline estimate for 2020 is attributable to wildfires.[375] However, as noted above, PG&E does not, through its testimony, claim to know with any precision the extent to which wildfires are driving these increases, and, in fact, its testimony suggests such an approach is unknowable.[376] CUE's witness admitted he is unsure of how the liability risks that PG&E faces are priced and that he has not studied the issue,[377] but in response to discovery on the issue, he offered PG&E's explanation of how insurance pricing works:

> Insurers do not break down pricing into individual factors and adders . . . [i]nsurers have their own unique models, methods, and procedures for determining how much capacity they are willing to offer any company and the price. The methods used to price an account generally are regarded by insurers as trade secrets.[378]

In light of PG&E's testimony, neither Cal Advocates nor CUE has presented convincing evidence that their proposal represents a reasonable estimate of the amount of the insurance expense increase due to wildfires.

PG&E's recorded data on its excess liability costs further illustrates that these increasing costs cannot all be attributed to wildfires, and in fact, likely stem from multiple unidentified factors neither mentioned nor considered in Cal Advocates' or CUE's proposals. PG&E's recorded data on these costs—listed in Cal Advocates' Table 17-3[379]—demonstrate that they were increasing sharply even before the major 2017-2018 wildfires, more than doubling from 2013 to 2017. The proposals do not attempt to isolate the various factors contributing to the

375 *See* Exh. 62 at 4-6.
376 Exh. 159 at 3-9:16-20.
377 13 Tr. 1334:20-25 and 1335:2-27 (CUE – Earle).
378 Exh. 63 at 3-4 (CUE Data Response to Joint CCAs DR 1).
379 Exh. 174 at 5:1-5.

sustained upward trend and how those and/or other factors (independent of wildfire risk) may have contributed to the most recent increase in the 2020 forecast.

Finally, even putting aside these substantial issues with the logic and accuracy of the alternative proposals, the adoption of either would set untenable precedent for future general rate cases. As the perceived risks among PG&E's various functions change over time, the Commission would be in the position of trying to isolate the various causes of the change in overall costs—a feat PG&E itself finds incredibly difficult, if not impossible, due to the nature of insurance pricing[380]—to divide the costs across these functions. This process would be complex and contentious to administer.[381] Further, the averaging and trend analyses presented by Cal Advocates and CUE are not adept at addressing a situation in which insurance premiums are rising due to more than one factor, *e.g.*, wildfires caused by PG&E's distribution system and liabilities caused by a gas storage leak or hydroelectric dam failure. Neither Cal Advocates nor CUE addressed how their methods would account for these complex realities going forward, and when pressed on this issue during cross examination, CUE's witness was unable to explain how his trend analysis could account for more than one factor driving increasing costs.[382]

Therefore, the JCCAs oppose both Cal Advocates' and CUE's proposals for cost reallocation given the significant risks PG&E faces across all its lines of business, the inability of Cal Advocates, CUE, or PG&E to identify the amount of the insurance cost increase attributable to wildfires, and the risk associated with adopting a new precedent ill equipped to handle complicated cost reallocations that account for more than one cost-driving factor.

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380 Exh. 159 at 3-9:16-20 and 3-10:10-15.

381 Exh. 215 at 42:18-20.

382 13 Tr. 1339:5-22 (CUE – Earle, where Dr. Earle was unable to explain how his trend analysis would be able to account for more than one factor causing insurance premiums to rise).

11.9.1 Cost Allocations

PG&E allocates Administrative and General costs to the utility's UCCs (functions) using the utility's Labor Allocator. PG&E's Labor Allocator is developed from recorded O&M labor, adjusted for one-time items. The summed total of O&M labor by UCC/utility function is calculated as a proportion of total labor for the utility and is then multiplied by total A&G costs to functionalize total A&G into UCC categories.

Consistent with how PG&E functionalizes many of its Customer Care program and service-related costs as discussed above in Section 8, many of PG&E's labor expenses associated with providing customer service (e.g., costs booked to FERC accounts 900-912) are functionalized into UCCs using the utility's 55/45 allocator to spread such costs between Electric Distribution and Gas Distribution. Based on the arguments presented by JCCAs above in Section 8, PG&E's 55/45 functional allocator of customer service-related costs does not reflect actual customer utilization of the utility's services. As such, the Commission should require PG&E to use the JCCAs functional allocator for customer-service related costs in developing its Labor Allocator. The JCCAs allocator of customer-service related costs functionalizes 13.21% of costs to Electric Generation, 42.84% of costs to Electric Distribution, and 43.95% of costs to Gas Distribution. PG&E should employ a Labor Allocator that reflects actual provision of customer service by applying the JCCA's functional allocation to FERC accounts. Doing so produces a Labor Allocator that allocates 30.9% of costs to Electric Generation, 43.2% of costs to Electric Distribution, and 25.9% of costs to Gas Distribution.

To better align cost recovery with cost causation and improve the utility's equity in cost recovery, the Commission should require PG&E to utilize this adjusted Labor Allocator in functionalizing A&G costs. Based on PG&E's RO model[383], the utility has a total of $1.314 billion in A&G expenses, and functionalizing these costs using the adjusted Labor Allocator allocates $406.1 million to Electric Generation, $567.9 million to Electric Distribution, and $340.7 million to Gas Distribution. PG&E offered no rebuttal testimony to challenge this approach.

12. RESULTS OF OPERATIONS (OTHER THAN RATE BASE ISSUES)

12.1 Cost Allocation

As discussed above, the Commission should require PG&E to use the JCCA's proposed adjusted Labor Allocator whenever the utility otherwise uses its Labor Allocator to functionalize costs. Beyond A&G costs discussed above in Section 11.9.1 above, based on review and analysis of the utility's RO Model,[384] PG&E also uses the Labor Allocator to functionalize costs associated with "Business" and "Other" taxes, as well as Depreciation and Return earned on Common Plant. Using the adjusted Labor Allocator developed by JCCAs to better align cost recovery with cost causation in customer service-related programming produces a functionalized allocation of "Business" and "Other" taxes and Common Plant Depreciation and Return as follows:

Cost Category	Total Cost ($000)	Adjusted Labor Allocator			Allocated Costs ($000)		
		Elec. Generation	Elec. Distribution	Gas Distribution	Elec. Generation	Elec. Distribution	Gas Distribution
TAXES: Business	$1,199	30.9%	43.2%	25.9%	$370	$518	$311
TAXES: Other	$13,723	30.9%	43.2%	25.9%	$4,239	$5,928	$3,556
Depreciation (Common)	$579,269	30.9%	43.2%	25.9%	$178,940	$250,233	$150,096
Net Return	$148,294	30.9%	43.2%	25.9%	$45,809	$64,060	$38,425

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383 *See* Exh. 216 at Attachment JAM-2, pp. 6-8 (PG&E Data Response to Joint CCAs DR 4, Q11, Q12).

384 *See* Exh. 216 at Attachment JAM-2, pp. 6-8 (PG&E Data Response to Joint CCAs DR 4, Q11, Q12).

(Common Plant)			
Total	$229,359	$320,739	$192,387

Once again, PG&E offered no rebuttal testimony to challenge this approach.

17. CONCLUSION

For the foregoing reasons, the JCCAs request that the Commission:

- Order that PG&E's CWSP be expanded, accelerated and closely coordinated with local governments to ensure compliance with the law and increase the effectiveness of microgrid resilience zones, specifically:
  - Require that the M10 Resilience Zones program be expanded to accommodate CCA-procured energy in CCA-specified locations.
  - Require that this effort be expanded to incorporate clean, permanent generation, allowing other LSEs to participate, with the costs recovered through the PPP charge.
  - If the Resilience Zone is not expanded in the above two ways, *i.e.*, if it is approved with PG&E as the sole developer of resilience zones, the $34.1 million capital costs for the program should be removed from PG&E's distribution revenue requirement and allocated solely to the generation revenue requirement.
  - Require PG&E to greatly accelerate the identification of resilience zones.
- Order that PG&E's proposed functionalization of CWSP Costs be revised such that the costs for the operational practices, situational awareness, and support programs for the CWSP be functionalized among all of PG&E's lines of business, with expenses allocated on the basis of an appropriate O&M labor allocator and capital

allocated as common plant. Order that Wildfire and Infrastructure Protection Teams (M25), Wildfire Cameras (M22), and Satellite Fire Detection Systems (M23) be functionalized in this manner as well. This recommendation reallocates $94 million in expenses and $129.3 million in capital across all lines of business.

- Adopt JCCAs recommended changes to the functionalization of certain Customer Care costs, as detailed in the following table[385]:

Item	Joint CCA Proposal ($000) Electric Generation	Electric Distribution	Gas Distribution
PG&E GRC Proposal	$2,375,133	$5,267,137	$2,129,109
Impact of Joint CCA Proposed Adjustments			
Directly Functionalize Certain Customer Service Program Costs	$13,271	($12,216)	($1,054)
Adjust Remaining "Common" Customer Cost Allocator	$11,247	($10,353)	($893)
Adjust "Common" Customer Costs in Labor Allocator	$28,409	($24,032)	($4,377)
Adjustments to "Locate & Mark Activities"	$0	($9,868)	$9,868
Acceptance of PG&E's Errata	$4,650	($11,473)	$6,823
Initial Proposed Revenue Requirement	$2,432,709	$5,199,194	$2,139,475
$ Change from PG&E GRC	$57,576	($67,943)	$10,367
% Change from PG&E GRC	2.4%	-1.3%	0.5%

- Order PG&E to track utilization of customer service functions going forward to develop allocators that better reflect utilization of shared services.

- Order PG&E to provide sufficient transparency and detail in future GRC filing to justify and explain its functionalization methodologies and results.

385 Exh. 216 at 5:9-10.

- Require PG&E to share real-time data that is made available from its Grid Modernization Investments with all CCAs and other load serving entities, or in the alternative, functionalize some of the costs of the Grid Modernization investments to the generation function to reflect the disparate benefit that bundled customers would receive from such real-time data availability.
- Reject both Cal Advocates' and CUE's recommendations to allocate certain excess liability insurance expenses only to the electric distribution and electric transmission functions, which if adopted, would reallocate anywhere between $238 to $300 million of these expenses.

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