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Re: **Pacific Gas and Electric Company's Comments on the Revised Draft 10-Year Electrical Undergrounding Plan Guidelines Issued by Energy Safety on September 13, 2024**

Dear Ms. Douglas:

Thank you for the opportunity to provide comments on the Revised Draft 10-Year Electrical Undergrounding Plan (EUP) Guidelines (Revised Guidelines) issued by Energy Safety on September 13, 2024. Our comments address 11 issues in the Revised Guidelines, identify one potential addition to the Guidelines for your consideration, and one issue we are concerned about regarding requirements in the Revised Guidelines and the California Public Utilities Commission (CPUC or Commission) SPD-15 that we raise for awareness. All section references in these comments refer to the Revised Guidelines.

We note that the Revised Guidelines introduce both new and more detailed requirements in the areas of risk modeling, project and sub-project scoping, status reporting and development, and tracking of targets and objectives. The Revised Guidelines include new, complex requirements, most notably the complex mitigation alternatives analysis, and the requirement to provide geospatial information about secondaries and services. The combination of the new, complex requirements on top of the already significant data and narrative requirements will require changes to how we operate our business, could de-emphasize wildfire risk in comparison to reliability risk, and will significantly delay our EUP submission without certain revisions or modifications, especially relating to mapping of secondary lines and services.

The items discussed below are listed in priority order with the first issue being the most significant. PG&E appreciates the work that has gone into developing these Revised Guidelines and we urge Energy Safety to expeditiously consider the parties' final comments and issue the final EUP Guidelines.

1. Scaled and Weighted Risk Calculations

Section 2.7.3 and Appendix A of the Revised Guidelines say that the Key Decision-Making Metrics (KDMMs) for Overall Utility Risk, Ignition Risk, Ignition Likelihood, and Outage Program Risk should be unweighted and unscaled calculations.[1] For the reasons described below, PG&E does not support this requirement and recommends that "unweighted and unscaled"[2] be removed from the Overall Utility Risk, Ignition Risk, Ignition Likelihood, and Outage Program Risk definitions. By removing "unweighted and unscaled" all risk-based decisions will be made, and all thresholds will be set, using risk scores that are derived from scaled calculations. PG&E does not oppose reporting unscaled risk scores for reference, but does not believe they are appropriate for driving risk-based decision making.

Determining Overall Utility Risk, Ignition Risk, Ignition Likelihood, and Outage Program Risk based on unweighted and unscaled calculations would be inconsistent with the methods PG&E uses to calculate these same values in our Risk Assessment Mitigation Phase (RAMP), Wildfire Mitigation Plan (WMP), and General Rate Case (GRC). Using an inconsistent method in the EUP would result in different risk scores among proceedings and would be inconsistent with how utilities and regulators have been measuring risk and how parties use that information in risk-based decision making.

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1 Revised Guidelines, p. 28. Page references in these comments are to the pages on the clean version of the Revised Guidelines issued on September 13, 2023.

2 PG&E interprets "unscaled and unweighted" calculations as the terminology from Multi-Attribute Value Function (MAVF) framework adopted in D.18-12-014 where natural units of consequence attributes are normalized, scaled using risk scaling function and then weighted. With the adoption of D.22-12-027 and D. 24-05-064, there is no longer a need to normalize and weight the consequence attributes because they are replaced by using monetized value of attributes. Risk scaling is still allowed to capture one's attitude towards varying levels of risk consequences.

Incorporating a scaling function into its risk calculations allows a Large Electrical Corporation to demonstrate its risk preferences. In the Risk-Based Decision-Making proceeding, the Commission stated that, "[r]isk scaling refers to applying a scaling function to the full range of an attribute to capture one's attitude towards varying consequences of risk events, particularly high-consequence outcomes at the tail end of a probability distribution of the attribute."[3] Scaling enables PG&E to remain consistent with the State's prioritization of catastrophic risk. Using unscaled values, as required by the Revised Guidelines would result in a different relative amount of risk between wildfire and reliability, which would be contrary to PG&E's approach towards managing risk in our territory. PG&E's primary focus is to select locations for undergrounding that will reduce the greatest amount of wildfire risk. We recognize the importance and legislative requirement of also improving reliability risk, and we will incorporate reliability improvements into our EUP, but not at the expense of reducing wildfire risk.

The Commission also recognized that Investor Owned Utilities (IOUs) should be allowed to express their values-based preferences, revising the definition of Risk Scaling Function to, "[a] function or formula that specifies an attitude towards different magnitudes of Outcomes including capturing aversion to extreme Outcomes or indifference towards those Outcomes" [4] Modifying the Revised Guidelines by removing the requirement to determine risk using unweighted and unscaled calculations would align with the Commission's recognition that IOUs should be allowed to express their values-based preferences.

Finally, the EUP allows a Large Electrical Corporation to use risk-scaling when developing certain risk measures. For example, in Section 2.7.5, Core Capability 1, the Revised Guidelines state that a Large Electrical Corporation must define any risk scaling used in the calculation of Project-Level Risk Analysis and must report the unscaled calculations as well. If it is reasonable to allow the Large Electrical Corporation to rely on scaled risk calculations for the Project-Level Risk Analysis, it is reasonable to use scaled risk calculations for other risk measures as well.

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[3] Decision (D). 24-05-064, May 30, 2024, p. 92.

[4] *Id.*, p. 98.

2. Mapping Secondary Lines and Services

The Geographic Information System (GIS) data schema described in Section C.4.1 requires a Large Electric Corporation to provide information about each circuit segment that includes both primary and secondary distribution lines. Table C.15 requires the Large Electrical Corporation to report all circuit segments representing its entire distribution system as a spatial data submission. Table C.17 requires line feature class information about subprojects planned for undergrounding and Table C.19 requires line feature class information about subprojects post mitigation. While PG&E supports providing secondary and services information, we recommend modifications to the Revised Guidelines in terms of how much information is required and when the information should be provided.

PG&E's Electric Distribution (ED) GIS system includes primary distribution line information, some secondary distribution line information and only limited information about the associated services (PG&E notes that secondary and service lines operate in the same voltage class and for planning purposes we consider secondary and service lines essentially the same). To confirm and update geospatial secondary line information and collect information about services and enter it into ED GIS before submission would significantly delay PG&E's EUP. Requiring PG&E to provide GIS information about secondary lines and services for the entire distribution system before submission is an unnecessary expenditure of time and resources. Information about services located outside the high fire threat district (HFTD) or in HFTD locations not selected for undergrounding is not needed for underground project selection. Rather, PG&E recommends that information about secondary lines and services be collected during scoping and underground project execution and input into ED GIS post-construction, during the project mapping phase. PG&E currently estimates that submission of our EUP would be delayed by over a year if the current requirements regarding ED GIS secondary and services information are not modified.

To address this issue PG&E recommends the following modifications to the Revised Guidelines.

- Table C.15 – Require a Large Electric Corporation to provide circuit segment information including primary and secondary distribution lines that are the basis of the utility's risk model.

- Table C.17 – Require a Large Electric Corporation to provide pre-mitigation circuit segment information including primary and secondary distribution lines, that are the basis of the utility’s risk model.

- Table C.19 – Require a Large Electric Corporation to provide post-construction circuit segment information including primary and secondary distribution lines and the associated services for undergrounding projects and subprojects when post-construction project mapping is completed.

3. <u>Project Level Threshold Changes</u>

The Revised Guidelines require that a Large Electric Corporation set and explain a High-Risk Threshold, Ignition Tail Risk Threshold, High Frequency Outage Program Threshold, and Mitigated Risk Threshold (the Thresholds). Section 2.7.9.2 states that the Project-Level Standards are fixed when the EUP is approved and cannot be altered when risk model versioning or calibration changes occur or when any other changes are made.

PG&E intends to use the outputs from its risk models to establish the Thresholds and expects that these outputs will change over time as models are updated. Therefore, PG&E does not support fixing these Thresholds for the duration of the EUP. For example, PG&E is developing an Outage Program Risk Model and anticipates this model will continue to evolve and become more refined during the 10-year EUP period. Fixing these thresholds may result in setting a threshold too low or too high based on a model that is expected to change over time.

PG&E recommends that the Guidelines allow a Large Electrical Corporation to change its Thresholds when risk modeling versioning occurs. The Large Electrical Corporation would explain the changes to them in its Model Report (Section 2.7.2). Further, as PG&E suggests in Section 12 below, PG&E recommends that a threshold change would be submitted as a change order request to Energy Safety detailing the proposed threshold modifications.

4. <u>Alternative Mitigation Analysis</u>

The Revised Guidelines require the Large Electrical Corporation to conduct multiple alternative mitigation analyses for each project — both in terms of the number of times the alternatives analysis required and the number of mitigations that must be analyzed. An alternatives analysis is required at Screen 2 and Screen 3 plus the Guidelines require a Large Electrical Corporation to return to Screen 2 and update its alternative mitigations analysis after projects are scoped at the end of Screen 3.

The proposed requirements in the Revised Guidelines include:

- Section 2.4.4 requires a Large Electrical Corporation to compare undergrounding to alternative mitigations to determine which Eligible Circuit Segments can be treated as undergrounding projects. This comparison occurs in Screen 2.
- Section 2.7.10 states that if a Large Electrical Corporation determines that an undergrounding project will require non-undergrounding subprojects, the project (circuit segment) must be analyzed both as the "Project as Scoped" and the "Undergrounding as Scoped" in Screen 3.
- Section 2.7.10 requires multiple alternative comparisons for each project. The mitigation alternative comparisons (referred to as "design variations") that are required per the Revised Guidelines include:
  - 100% Undergrounded (Screen 2)
  - Project as Scoped – Required if a project includes non-undergrounding subprojects. Includes all work in the final project design (Screen 3)
  - Undergrounding as Scoped - Required if a project includes non-undergrounding. Includes only the undergrounding subprojects (Screen 3)
  - Baseline – The unmitigated circuit segment must be compared to the undergrounding project (Screen 3)
  - Alternative Mitigation 1 – Installation of covered conductor with protective equipment and device settings (Screen 3)
  - Alternative Mitigation 2 – Mitigation or combination of mitigations that meet or exceed the risk reduction of Alternative Mitigation 1 (Screen 3)
  - Update the Screen 2 comparison to include both the Project as Scoped and the Undergrounding as Scoped

PG&E supports conducting an alternative mitigation analysis in Screen 2. An alternatives analysis will provide Energy Safety and stakeholders visibility into mitigation selection and will help confirm that a Large Electrical Corporation is selecting the right mitigation in the right locations. However, the scope of the alternative analyses required in the Revised Guidelines, including the requirement to return and update the Screen 2 analysis after work is scoped in Screen 3, is an unnecessary level of effort and complexity. Thus, PG&E does not support the alternative mitigation requirements in the Revised Guidelines.

In an effort to streamline the alternative mitigation analyses PG&E recommends the following changes to the Revised Guidelines.

- 100% Undergrounded - The initial alternatives analysis that PG&E will conduct will be a comparison of Cost Benefit Ratios (CBRs), KDMMs, and/or other metrics. If this initial analysis shows that 100% Undergrounded (Underground All) is unfavorable compared to other mitigation options, no additional scoping or design of this solution should be required. It is an inefficient use of resources to scope and design a project that the Large Electrical Corporation knows that it will not execute.

- Alternative Mitigation 2 - PG&E recommends defining Alternative Mitigation 2 as the hybrid mitigation that is made up of the alternatives "Project as Scoped" and "Undergrounding as Scoped." In most cases, the hybrid solution will be the only mitigation that will address the requirement that Alternative Mitigation 2 meet or exceed the risk reduction of Alternative Mitigation 1. The 100% underground and 100% overhead mitigation analyses in Screen 2 will inform the hybrid solution. If a Large Electrical Corporation cannot consider Alternative Mitigation 2 to be the hybrid solution, it could be forced to model and report on a fabricated alternative mitigation that is not part of its suite of mitigation options, is operationally infeasible, or is cost prohibitive. Requiring this comparison is unnecessary and creates additional work for no additional value. PG&E raised this same concern in our August 8, 2024, comments.[5]
- Eliminate the requirement to scope Alternative 2 if the initial alternatives analysis based on a comparison of CBRs, KDMMs, or other metrics indicates that 100% Undergrounded is the preferred solution.

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5 PG&E's Comments on Issues Raised by PG&E and other Topics Discussed at the Workshop Held July 25, 2024 by Energy Safety on the Draft Electrical Underground Plan Guidelines, p. 6.

5. Risk Targets and Metrics

The Revised Guidelines include several required tracking and monitoring measures made up of metrics, objectives, targets, thresholds and standards. These measures will be monitored over different time periods including six-month updates, annually, cumulatively over five years, and over the life of the EUP. PG&E agrees that the EUP must include measures to track and evaluate a Large Electrical Corporation's progress towards meeting the Plan Mitigation Objective (the total amount of change in combined wildfire and reliability risk that is necessary to meet the requirement of Senate Bill (SB) 884, Section 8388.5(d)(2)).

However, the number of, and interrelationships among the metrics, objectives, targets, thresholds and standards in the Revised Guidelines will significantly restrict how a Large Electric Corporation selects and executes a portfolio of work. Managing to multiple tracking metrics will be extremely difficult because of the challenges in selecting and executing projects that will enable us to meet the various requirements. Accounting for system-level, portfolio-level and project-level measurements for the Plan Mitigation Objective, Portfolio-Level Standard, KDMMs, Project-level Standard, Project-level Threshold, Plan Tracking Objectives, and the Target/Timeline Table, the Revised Guidelines include 56 metrics or other measurements. For reference, in PG&E's base 2023-2025 WMP we are managing to 82 targets and objectives over the three-year WMP cycle across all our distribution and transmission wildfire mitigation programs. Only two of the targets are associated with the undergrounding work (GH-01 System Hardening miles and GH-04 Undergrounding miles). Managing our EUP program to address so many different measurements will significantly limit PG&E's operational flexibility and make it more difficult to execute a successful portfolio of wildfire and reliability risk reduction work.

An undergrounding program consisting of hundreds of individual projects with multiple dependencies is dynamic. Changes will occur over the course of the 10-year plan. Many of the challenges we regularly encounter on an undergrounding job are due to delays and other issues that are outside of our direct control, such as permitting delays, coordinating access with landowners, and challenges such as dealing with weather conditions or unexpected hard rock encountered during construction. Additionally, it would be difficult to meet annual reliability targets since benefits may not be realized until projects upstream or downstream of a circuit segment are complete and the upstream/downstream projects may not be completed in the same year.

The Revised Guidelines state that the Independent Monitor will use the Plan Mitigation Objective, Plan Tracking Objectives, and other objectives to assess the Large Electrical Corporation's compliance with its EUP. There is no information in the Guidelines about how the Independent Monitor will use metrics to confirm compliance with the EUP, which metrics will be most important to the Independent Monitor's evaluation, and what would occur if the Large Electrical Corporation failed to meet one or more metrics. The Revised Guidelines should be limited to key metrics for determining compliance with the EUP with other metrics clearly identified as "reporting only" and unrelated with EUP compliance.

To address the challenges with executing a portfolio of undergrounding projects against multiple tracking and monitoring measures, while still providing Energy Safety and stakeholders visibility into a Large Electric Corporation's progress towards meeting the Plan Mitigation Objective, PG&E recommends the following changes.

- Remove the requirement to provide System-Level metrics from the Plan Tracking Objectives (Section 2.3.2), Key Decision-Making Metrics (Section 2.7.3 and Section 2.8.6.2), and Portfolio-Level Standards (Section 2.7.8). The SB 884 legislation limits undergrounding work to the Tier 2 and Tier 3 areas of the HFTD and rebuild areas.[6] In PG&E's territory, approximately 90 percent of wildfire risk is in the HFTD. Requiring a Large Electrical Corporation to report system-wide metrics is time consuming and unnecessary.
- Section 2.3.1, Table 1 lists several targets a Large Electrical Corporation must provide in support of its Plan Mitigation Objective. PG&E recommends removing Overhead Miles Deenergized (discussed below) and Preconstruction Miles. PG&E supports reporting information that aligns with the requirements of SB 884 Section 8388.5(c)(3) and 8388.5(d)(2): (Underground) Miles Completed; Cumulative Miles Completed; Unit Cost Target; Change in Instantaneous Wildfire and Outage Program

[6] Cal. Pub. Util. Code § 8388.5(c)(2).

Risk in Year 10; and Change in Cumulative Wildfire Risk and Outage Program Risk over 50 Years.

- Section 2.3.2 lists Plan Tracking Objectives that will be used to assess if the Large Electric Corporation is on track to meet the Plan Mitigation Objective. PG&E generally supports the inclusion of Plan Tracking Objectives but recommends several changes.

  Item (b) states that a Large Electrical Corporation must include annual and 5-year targets. PG&E recommends changing this requirement from requiring targets to requiring reporting only. Establishing annual and 5-year targets for a dynamic program is unreasonable because the program achievements will vary year over year. Achieving the 10-year targets and objectives should be the standard against which the Large Electrical Corporation is measured. PG&E does not oppose requiring a Large Electrical Corporation to report progress against key targets (e.g. unit cost and underground miles complete) on an annual and 5-year basis and explain how that progress aligns with delivering on the overall 10-year plan targets. As discussed above (Section 2.3.1), PG&E does not oppose annual targets for unit costs and underground miles completed.
  Item (d) and (e) are the same requirement though one is a target and one an objective. PG&E recommends removing target item (d) because it appears these are duplicative. PG&E recommends removing the duplicative target.

  Item (f) states that an EUP must include tracking objectives measured by risk reduced per mile. PG&E does not recommend using risk reduced per mile (risk density) as a target because it will not be indicative of overall risk reduction on the system. If risk per mile becomes a target, it would reduce our flexibility in how we prioritize and manage risk mitigation deployment which can increase costs and slow risk reduction.

PG&E addressed this same issue in our comments on the July 25, 2024 Energy Safety EUP workshop.[7]

Item (g) requires tracking objectives measured in miles of overhead line deenergized. The miles of lines removed will be accounted for in the risk reduction calculation. A Large Electrical Corporation will develop its portfolio of work over the life of the program. Establishing an objective for the number of overhead miles deenergized when the EUP is submitted will limit flexibility in selecting and designing undergrounding work. PG&E does not oppose requiring a Large Electrical Corporation to report line miles of overhead line de-energized on an annual and 5-year basis.

Item (h) states that an EUP must include tracking objectives measured in number of projects that have completed Screens 3 and 4. PG&E does not support item (h) because the EUP priority should be ignition risk reduction and reliability improvements. Measuring the number of projects confirmed, scoped, and completed does not advance these priorities. Further, the number of projects may fluctuate significantly as each project differs in size and risk. As such, the number of projects in any particular period of time may simply not be relevant to the overall objectives of the EUP. We note that electrical corporations will report project status updates in their status reports and the information will be available for review. PG&E addressed this same issue in our comments on Energy Safety's July 25, 2024 workshop.[8]

6. <u>Project Table Requirements</u>

Section C.1.10 (Table C.10) of the Revised Guidelines establishes the requirements for a Project Table that contains information about each undergrounding project as an individual row. The Revised Guidelines require a Large Electrical Corporation to provide an order number that

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7 PG&E's Comments on Issues Raised by PG&E and other Topics Discussed at the Workshop Held July 25, 2024, by Energy Safety on the Draft Electrical Underground Plan Guidelines, p. 4.

8 PG&E's Comments on Issues Raised by PG&E and other Topics Discussed at the Workshop Held July 25, 2024, by Energy Safety on the Draft Electrical Underground Plan Guidelines, p. 4.

matches the requirements in Appendix 1 of the CPUC's SB 884 Guidelines.[9] Specifically, the PROJECT_ID on Table C.10 must map one-to-one to the "ORDER" category as defined in the CPUC SPD Resolution 15 EUP-related Guidelines (SPD-15 or CPUC Guidelines). The CPUC Guidelines define "order" as a unique project order number.

PG&E supports the requirement to provide unique Order Numbers to both Energy Safety and the CPUC. However, due to a difference in how the term "project" is used in the EUP and CPUC Guidelines (discussed below), PG&E cannot provide a Project ID that maps 1:1 to an Order Number. We will provide unique Order Numbers for each subproject[10] to allow Energy Safety, the CPUC and stakeholders to easily track the undergrounding work that we execute and for which we seek cost recovery.

The work that the CPUC Guidelines consider a "project" is the work that is referred to in the Revised Guidelines as a subproject.

- In the Energy Safety Guidelines a project is defined as an individual isolatable circuit segment. A project may be divided into one or more subprojects for operational reasons or to reflect portions of circuit segments that will be treated with different wildfire mitigations. Subproject is a defined term in the Energy Safety Guidelines.

- The CPUC Guidelines recognize that, "[s]coping includes breaking out planned circuit segments into smaller, more manageable projects."[11] In the Energy Safety nomenclature, breaking a planned circuit segment into smaller projects would be referred to as a "subproject." While the CPUC Guidelines contemplate work being broken out on a subproject basis they do not use the term "subproject." At the time the CPUC Guidelines were developed, parties participating in the development of them did not use that term.

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9 The CPUC Guidelines were adopted in Resolution SPD-15 (March 8, 2024).

10 PG&E anticipates that most of the work we will complete will be made up of hybrid subprojects. If PG&E undergrounds an entire circuit segment we will provide a unique Order number for that project.

11 Resolution SPD-15, Appendix 1, p. 15.

CPUC Guidelines Appendix 1 require a Large Electrical Corporation to provide data about projects included in the Plan (10-Year Undergrounding Plan) and in the Application (the application submitted to the Commission requesting review and conditional approval of the Plan's costs). The required data includes a unique project order number. PG&E will be seeking to recover costs on a subproject basis[12] as soon as work is completed and considered used and useful. PG&E will provide a unique Order Number to the CPUC for the subproject work we complete and for which we seek cost recovery.

Ultimately, PG&E will provide a unique Order Number for the work — either a project (a complete circuit segment) or subproject (the portion of a circuit segment that will be undergrounded) — that it is part of our Energy Safety EUP portfolio of work and for which we are seeking cost recovery through our CPUC cost application. However, because of the difference in how the term project is used in the two sets of guidelines, the Order Numbers that PG&E will provide to Energy Safety and the CPUC will not map one-to-one to the PROJECT category as required by Energy Safety.

Table 1 below shows the relationship among Project IDs, Order Numbers, projects and subprojects. In Table 1, the EUP project (circuit segment) is MapleAve123. This project is divided into several subprojects, five of which will be undergrounded and will be in the EUP portfolio of work. PG&E assigned Project ID PROJ-001 to the MapleAve123 circuit segment and all underlying subprojects. We assigned a unique Order Number to each individual subproject.

[12] As indicated in footnote 10, PG&E anticipates that most of the circuit segment level work we will complete will be made up of hybrid subprojects though there may be some entire circuit segments that are undergrounded.

TABLE 1
THE RELATIONSHIP AMONG PROJECT IDS, ORDER NUMBERS, CIRCUIT SEGMENTS AND SUBPROJECTS

Subproject	Project ID	Order Number	Circuit Segment Name	Subproject Mitigation
1	PROJ-001	3331230	MapleAve123	Undergrounding
2	PROJ-001	3331231	MapleAve123	Undergrounding
3	PROJ-001	3331232	MapleAve123	Undergrounding
4	PROJ-001	3331233	MapleAve123	Undergrounding
5	PROJ-001	3331234	MapleAve123	Undergrounding

- In EUP Table C.10, in the field "project_id," we will include five rows, one for each of the MapleAve123 subprojects. Each subproject rolls up to the same Project ID (PROJ-001).

- The CPUC Guidelines, Appendix 1, requires a "Unique Project Order Number." To comply with this Appendix 1 requirement, we will provide the unique Order Number for each subproject. This will allow cross-referencing between the EUP submission and our CPUC application.

7. <u>Circuit Segments Transversing HFTD and Non-HFTD Areas</u>

The Revised Guidelines define HFTD as areas of the state designated by the CPUC as having elevated wildfire risk, where each Large Electrical Corporation must take additional action to mitigate wildfire risk pursuant to Decision 17-01-009 or its successor. The HFTD maps that were developed by the CPUC do not align to PG&E's electric grid and, therefore, there are areas in PG&E's territory where circuit segments cross an HFTD boundary into a non-HFTD area. In some cases, the circuit segment crosses back and forth between HFTD and non-HFTD areas. PG&E recommends that if any portion of a span[13] is in the HFTD then the entire span should be considered to be in the HFTD and eligible for inclusion in the EUP. Excluding spans from EUP

[13] A span is the overhead electric line between two poles and is generally several hundred feet in length.

eligibility that are partially outside of the HFTD would significantly hinder constructability, increase project costs, and increase impacts on the community where work is occurring because projects or subprojects would be routed in inefficient ways and/or unnecessarily require sections of overhead hardening where circuit segments cross the HFTD. Allowing a Large Electric Corporation to consider an entire span within an HFTD when any portion of the span is in the HFTD is consistent with the definition of "Undergrounding Support Work" in the Revised Guidelines[14] that allows for non-undergrounding work to be included in the EUP when it is done in direct support of undergrounding distribution lines.

PG&E recommends revising the definition of HFTD in the final Guidelines by adding the underlined text as follows:

> "HFTD" or "High Fire-Threat District" means areas of the state designated by the CPUC as having elevated wildfire risk, where each Electrical Corporation must take additional action to mitigate wildfire risk pursuant to Decision 17-01-009 or its successor. <u>In situations where a portion of a span is in the HFTD, the entire span is considered to be in the HFTD.</u>

8. Wildfire Rebuild Area Work

The Revised Guidelines now include information about undergrounding in wildfire rebuild areas. The most significant requirements related to wildfire rebuild areas include:

- Section 2.3.5(a) and Section 2.4.3.2 state that if a circuit segment in a wildfire rebuild area does not meet a Project-Level Threshold, the Large Electrical Corporation must provide justification for designating the circuit segment as an Eligible Circuit Segment. The justification must include details about the extent of the damage to the circuit segment and should describe why it should be considered an Eligible Circuit Segment.

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14 "Undergrounding Support Work" means the work done in direct support of Undergrounding distribution lines. This includes work and equipment that (i) directly facilitates Undergrounding lines, (ii) transitions between overhead and underground lines, or (iii) is required by construction or design standards or GO 95. This may include the construction of no more than three new distribution poles on either end of an undergrounded portion of distribution line if they are necessary to facilitate the safe transition from overhead to underground.

PG&E agrees that circuit segments in wildfire rebuild areas that do not meet a Project-Level Threshold should be eligible for the EUP but does not support how the Large Electrical Corporation would justify eligibility as required by the Guidelines.

PG&E has developed extensive operational processes focused on ensuring public, employee and contractor safety while expediting the disaster response for restoring and rebuilding significantly interrupted services caused by wildfires. The requirements in the EUP for justifying a circuit segment impacted by wildfire as an Eligible Circuit Segment run counter to PG&E's responsibility to expeditiously rebuild damaged electrical infrastructure. Waiting for a decision as to whether a damaged circuit segment would become EUP eligible would significantly hamper PG&E's restoration and rebuild efforts. Taking time to justify mitigating realized risk is unreasonable. A better approach would be to immediately designate any circuit segment damaged by wildfire as EUP eligible so that rebuild work could proceed as quickly as possible.

PG&E recommends that all circuit segments in the HFTD areas that need to be rebuilt due to damage from a wildfire automatically become Eligible Circuit Segments. Once infrastructure is damaged by wildfire it becomes "realized risk" — the risk of a wildfire damaging the asset is now a reality — and the most appropriate response would be to manage future wildfire risk through system hardening. Circuit segments in an HFTD wildfire rebuild area would be subject to the same Screen 2 and Screen 3 requirements as other eligible circuit segments.

- Section 2.3.5(c), indicates that the risk reduction from a wildfire rebuild area undergrounding program does not count for purposes of determining progress towards the Plan Mitigation Objective and Plan Tracking Objectives. PG&E's understanding of this requirement is that it only applies to circuit segments that are in a wildfire rebuild area but are not Eligible Circuit Segments. PG&E recommends clarifying that Section 2.3.5(c) only applies to wildfire rebuild projects that are not Eligible Circuit Segments. PG&E's recommendation assumes that all fire rebuild circuit segments in the HFTD automatically become Eligible Circuit Segments without further justification as discussed in our comments on Section 2.3.5(a) above.

- Section 2.4.3.1 states that in Screen 1 the Large Electrical Corporation must specify which circuit segments are located in a wildfire rebuild area. Additionally, it must provide information about the wildfire rebuild areas including if any distribution infrastructure damaged in the wildfire has already been rebuilt. Stating that only circuit segments that have been damaged by wildfire and have not previously been rebuilt are eligible.

  PG&E does not support this requirement. Circuit segments that were hardened after a wildfire using covered conductor should be eligible for the EUP if they pass the screening and project-level threshold requirements. Even after overhead hardening there may still be significant risk on certain circuit segments. It may have been prudent to install overhead covered conductor at the time certain circuit segments in wildfire rebuild areas were rebuilt. Today, with more sophisticated risk models and a better understanding of wildfire risk in certain locations, it may now be reasonable to underground them. PG&E recommends modifying the Revised Guidelines to allow all circuit segments that pass the screening and project-level threshold requirements to be considered an Eligible Circuit Segment, whether or not they were previously rebuilt.

9. <u>Changes to a Circuit Segment</u>

The Revised Guidelines require that a Large Electrical Corporation account for physical changes to a circuit segment such as relocating lines for operational reasons, the addition or removal of equipment that redefines the endpoints of a circuit segment, or changes in alignment. Sections 2.4.2.4 and C.1 state that a circuit segment is considered "new" and requires a new Circuit Segment ID if equipment that defines the boundaries between circuit segments are moved, removed, or added. PG&E does not support this requirement.

PG&E understands that this requirement is limited to physical changes to a circuit segment that is used as a basis for risk-based decision making. PG&E's current ignition risk model

(Wildfire Distribution Risk Model, Version 4 or WDRM v4) is based on PG&E's electric grid as it was configured on January 1, 2023. All decisions to harden a circuit segment will be made based on this configuration for as long as PG&E uses WDRM v4. When PG&E updates its ignition risk model it will be based on the grid as it is configured some date in the future — for this discussion, we will assume we update the ignition risk model on January 1, 2028, to WDRM v5 and that we begin using WDRM v5 on the same day. Under the Revised Guidelines, PG&E would provide information to Energy Safety showing the physical changes to the circuit segments from January 1, 2023 to January 1, 2028 with the first six month report we submit after January 1, 2028 by filling out the Circuit Segment Changelog Table (Table C.6). In the six-month reports that we submit prior to January 1, 2028, we would indicate "no change" on the Circuit Segment Changelog table because we would still be making system hardening decisions based on how the grid was configured on January 1, 2023 using WDRM v4.

PG&E recommends that the Revised Guidelines be modified in such a way to confirm our understanding. PG&E proposes that Section 2.4.2.4 be revised as follows (proposed text is shown in <u>underline</u>):

> The EUP must account for physical changes to a Circuit Segment such as relocating lines for operational reasons, the addition or removal of equipment that redefines the endpoints of a Circuit Segment, or changes in alignment due to undergrounding itself, among other factors. <u>Physical changes must be accounted for only when the change impacts how a Large Electrical Corporation evaluates risk on that Circuit Segment such when it updates it risk model.</u> This is accounted for in three ways.

Additionally, the Revised Guidelines state that Circuit Segments must be represented by unique identification names and cannot be reused for a "new" Circuit Segment. A Circuit segment is considered new and requires a new Circuit Segment ID if equipment that defines the boundaries are moved, removed, or added.

PG&E's circuit segment names are based on the interrupter device on that segment. If, for example, a new interrupter device is added and what was one circuit segment becomes two, one circuit segment retains the original circuit segment name and the new circuit segment receives a new name based on the new interrupter device. In this example, PG&E would be "reusing" a circuit segment name as defined by the Revised Guidelines. If PG&E is required to create a new name for the portion of the circuit segment that retained the original name, the naming of that circuit segment would be inconsistent between PG&E's system of record and the EUP. PG&E recommends that a Large Electrical Corporation be allowed to retain the original name of a circuit segment, consistent with its system of record, even if it has changed in some manner, and only provide new names for newly created circuit segments.

10. <u>Geospatial Data Requirements</u>

PG&E identified four issues in the geospatial data schema requirements that we recommend be revised or clarified in the final Guidelines.

- Section C.1.13 establishes the requirements for a Subproject Table. These requirements include reporting a pre_mitigation_alignment_id and post_mitigation_alignment_id — values that are mapped to geo-spatial submissions. The pre- and post-mitigation geospatial submissions tables, Tables C.4.4 and C.4.4.6, do not include the pre_mitigation_alignment_id and post_mitigation_alignment_id data points. PG&E assumes that this indicates that we will need to display the line feature classes for C.4.4 and C.4.6 on a subproject level, as that is the level at which we produce line geometry in our scoping and design process. In that case, PG&E would use the subproject ID Number for both the pre_mitigation_alignment_id and post_mitigation_alignment_id as that is the unique key we can use to map the subproject table to the geospatial submission.

  PG&E would appreciate if Energy Safety can confirm in the Final Guidelines that this approach is acceptable and there is no intention to create new pre-mitigation_alignment_id and post-mitigation_alignment_id values in both the Subproject Table and the GIS Line Feature Class tables.

- Section C.4.2 suggests that the Project Polygon should be a rectangle drawn around a line segment (Bounding Box). Doing that means that we will include asset GIS data not associated with the project being drawn because other assets, including lines from other circuit segments, are sometimes in close physical proximity to one another. If the goal is to try to minimize assets that are not associated with the project being pulled into the project polygon, PG&E recommends allowing the Large Electrical Corporation to create a project polygon based on a buffer zone with location-appropriate dimensions.

- Sections C.4.4 and C.4.6 require a Large Electrical Corporation to track pre-mitigation line features and assets to compare against post-mitigation line features and asset classes. PG&E's ED GIS is its system of record and as such it is updated when line features and assets on the system change. Historic GIS information is not maintained and post-mitigation assets may not have any relationship to pre-mitigation conductor. PG&E recommends that the Revised Guidelines omit the references to pre-mitigation alignment and asset features data from the post-mitigation alignment and asset feature data tables. The pre-mitigation to post-mitigation alignment can be determined using the project or sub-project ID.

  Sections C.4.4 and C.4.6 also state that the Large Electrical Corporation must report on some overhead assets other than conductor identified for removal or undergrounding such as capacitor banks, fuses, switchgears, transformers, and support structures. PG&E can provide information about some overhead assets other than conductor but may be unable to provide asset feature classes for all of the asset types of listed in the revised draft Guidelines. Additionally, PG&E may not be able to assign an asset to only one project with certainty (e.g. if an asset is located at a vertex shared by two projects). PG&E recommends that the Guidelines recognize that a Large Electrical Corporation will provide as much overhead asset data as is available in GIS and that certain assts may be associated with more than one project. Additionally, PG&E recommends the following modifications to the Revised Guidelines.

  — Table C.18: Require a Large Electric Corporation to provide pre-mitigation asset data that is the basis of the utility's risk model.

  — Table C.20 - Require a Large Electric Corporation to provide post-mitigation asset data when post-construction project mapping is completed.

11. Reporting Requirements for Non-EUP Projects

The Revised Guidelines list several requirements related to non-EUP projects.

- Section 2.4.7.2 requires a brief overview of all non-EUP undergrounding projects and all other distribution system hardening programs including a timeline for completion of non-EUP projects, their status, and their associated risk reduction. The Large Electrical Corporation must describe how the selection process for the non-EUP projects and programs is different from the EUP and how the programs will be coordinated.

- All of the information must be updated required in Section 2.4.7.2 must be updated in each six-month progress report.

- The Large Electrical Corporation must describe how the non-EUP projects are accounted for in the risk models.

- Section C.1.6 (Table C.6) requires a Large Electrical Corporation to list the external funding sources for mitigating non-EUP circuit segments, including funding for both undergrounding and other system hardening solutions.

PG&E appreciates that Energy Safety has reduced the amount of information needed for the non-EUP projects but does not support the requirements in the Revised Guidelines. PG&E already reports on much of the information that is being requested, though in different formats, in publicly available reports. Collecting, reconciling, and reporting information about projects that may be outside of the HFTD, or for which we cannot calculate risk reduction,[15] is an unnecessary use of resources when PG&E already publishes information about the non-EUP projects in other proceedings.[16] PG&E recommends the following changes to the Guidelines.

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15 PG&E cannot calculate risk reduction for new capacity projects because those new circuit segments will not be in the current risk models. We could only calculate risk reduction for them when we update our risk models.

16 PG&E discussed this issue in our Comments on Issues Raised by PG&E and other Topics Discussed at the Workshop Held July 25, 2024, by Energy Safety on the Draft Electrical Underground Plan Guidelines, p. 1.

- Revise Section 2.4.7.2 to require a brief overview of all non-EUP undergrounding projects and programs, their associated risk reduction at a program level (for example, provide the estimated overall risk reduction from overhead hardening during a GRC period but not the risk reduction of individual projects), how projects are selected for the non-EUP programs and how they will be coordinated at the time a Large Electrical Corporation submits its EUP.

- Remove the requirement to provide updates with every six-month progress report. Instead, allow the Large Electrical Corporation to provide links to publicly available information that tracks the non-EUP programs. This could include links to Rule 20A and system hardening annual reports.

- Revise Section C.1.6 to require a narrative description of how non-EUP programs are funded at the time the EUP is submitted. Do not require the Large Electrical Corporation to identify funding sources for each non-EUP project every six months.

12. <u>Change Order Process</u>

Section 2.4.2 describes the process for accounting for changes to circuit segment information, subprojects, physical changes to a circuit segment and expected or know changes. The Revised Guidelines also include procedures for other changes such as updates to risk models (Section 2.7.2).

Given the 10-year duration of the EUP, PG&E recommends adding a process to the Guidelines allowing for: 1) changes to a Large Electrical Corporation's EUP that are not expected or known at the time the plan is submitted; and 2) changes to the Guidelines themselves.

For minor changes to an EUP (e.g. adding an item to the progress report template), PG&E recommends that a Large Electrical Corporation propose the change in a six-month progress report. For substantive changes to an EUP (e.g. introducing a new mitigation alternative), PG&E recommends that a Large Electrical Corporation submit a change order request to Energy Safety detailing the proposed change. For substantive changes, it would be reasonable to expect data requests from Energy Safety or meetings to explore the proposed change.

PG&E also recommends adding a process allowing for changes to the Guidelines themselves. Energy Safety issues revised guidelines for each base Wildfire Mitigation Plan (WMP). The guidelines are updated to reflect changes to processes, data requirements, and required analyses over the three years since the prior base WMP was submitted. Over the course of the 10-year EUP, it is likely that changes or updates to the Guidelines should be considered. PG&E recommends implementing a change order process that allows Energy Safety or a Large Electric Corporation participating in the EUP to submit a change order request recommending changes to the EUP Guidelines.

13. Risk Mitigation Threshold Concern

Lastly, we are concerned about the relationship between the annual cost-benefit ratios CBRs in SPD-15 and the Mitigated Risk Threshold requirement in the Revised Guidelines. SPD-15 requires a Large Electrical Corporation to establish CBRs for all projects completed in any given two-year period which encourages the Large Electrical Corporation to prioritize projects that provide the greatest risk reduction benefits per dollar spent.[17] The Revised Guidelines require a Large Electrical Corporation to establish and explain a Mitigated Risk Threshold that is the combined measure of Ignition Risk and Outage Program Risk, below which a Circuit Segment is of acceptable risk. PG&E supports both these measures but has determined that in certain instances an individual project or subproject that we select will not meet both and we would need to choose between cost effectiveness and risk mitigation. PG&E supports allowing for the inclusion of projects in the EUP that do not meet the Project-Level Standards by providing a narrative justification.[18]

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[17] Resolution SPD-15, p. 11.

[18] See for reference, Section 2.7.9.2 which states that it is not necessary for every Undergrounding Project in the Portfolio to meet these Project-Level Standards, but any Confirmed Project which does not meet the appropriate Project-Level Standard must be further justified in the narrative submission associated with the Confirmed Project in the relevant section of the tabular data submission.

Thank you in advance for considering our comments. Please feel free to contact me if you have questions about these items or need additional information from me at Megan.Ardell@pge.com.

Very truly yours,

/s/ Megan Ardell

Megan Ardell