PACIFIC GAS AND ELECTRIC COMPANY
10 Year Electrical Undergrounding Plan (EUP)
Data Response

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SUBJECT: ALTERNATIVE MITIGATIONS AND PORTFOLIO PROJECT SELECTION

Selection of Alternative Mitigation Strategies for Screens 2 and 3

QUESTION 001

Provide the analyses and decision criteria supporting PG&E's selection of the Alternative Mitigation strategies used in Screens 2 and 3:

a. Identify the mitigation types and combinations of mitigation types PG&E evaluated for inclusion in its Alternative Mitigation framework, including any which were excluded.
b. Describe the screening criteria applied to each candidate mitigation, including technical feasibility, risk reduction, reliability, costs, scalability, readiness, and applicability to the EUP Circuit Segment population.
c. Explain why PG&E selected overhead hardening and 100% Remote Grid as the Screen 2 alternatives and how PG&E determines that these alternatives constitute useful comparisons to undergrounding.

ANSWER 001

PG&E's Project Acceptance Framework evaluates permanent wildfire mitigation strategies at different levels of project maturity in Screens 2 and 3. Screen 2 uses standardized design variations to provide a consistent and transparent comparison of mitigation alternatives across Eligible Circuit Segments based on the information available at that stage. Screen 3 incorporates more detailed project-specific information developed through scoping, including feasibility, constructability, local conditions, project configuration, and updated scope and cost information.

Accordingly, the Screen 2 comparisons do not establish that each modeled alternative is technically feasible or preferred for implementation across the entirety of every Eligible Circuit Segment. Rather, they provide a standardized basis for comparing undergrounding with other permanent mitigation strategies. Screen 3 then provides a more refined, project-specific comparison based on the available project scope and

feasibility information. The EUP specifically explains that PG&E uses homogeneous mitigation design variations at Screen 2 to provide a logical, consistent, and transparent basis for comparison, while Screen 3 incorporates more detailed project-scope and feasibility information (EUP Vol. 1, Ch. 3, Section D.2, pp. 110-111; Table 3-9, p. 115).

a. PG&E evaluates the following permanent-infrastructure design variations through the Project Acceptance Framework (EUP Vol. 1, Ch. 3, Section D.2, pp. 110-111; See Table 3-9, p. 115 for detailed descriptions):

Screen	Comparison	Mitigation(s)
Screen 2	100% Underground (100% UG)	100% UG includes relocating existing high-risk overhead primary distribution lines underground. PG&E currently also undergrounds secondary and service lines that run parallel to the UG primary lines
Screen 2	Alternative Mitigation 1 (Alt 1)	100% overhead hardening (covered conductor and associated framing)
Screen 2	Alternative Mitigation 2 (Alt 2)	100% Remote Grid with line removal, where feasible
Screen 2	Additional Comparison 1 (AC 1)	Hybrid – 50% underground / 50% overhead hardening
Screen 3	100% UG	Undergrounding; may include small overhead-hardened portions only where required for feasibility (e.g., Transmission-line under-build)
Screen 3	Screen 3 Alternative Mitigation (S3 AM)	Best-BCR non-undergrounding option: covered conductor, remote grid, or a combination, where feasible
Screen 3	Additional Comparison 2 (AC 2)	Scoped hybrid of undergrounding, overhead hardening and/or remote grid
Screen 3	Additional Comparison 3 (AC 3)	Best-BCR alternative (100% UG, S3 AM, or AC 2 plus Remote Grid / LEIP where feasible)

These design variations reflect the distinction between the standardized comparisons conducted at Screen 2 and the project-specific configurations evaluated at Screen 3. The 50% Undergrounding and 50% Overhead-Hardening Hybrid is treated as an Additional Comparison rather than an Alternative Mitigation because it includes undergrounding. The EUP Guidelines define “Alternative Mitigation” as a mitigation strategy, other than Undergrounding, used to reduce the consequence or likelihood of wildfires and Outage Program Events on a particular Circuit Segment (EUP Guidelines, Appendix A). The Guidelines separately require comparison of 100% Undergrounding against two Alternative Mitigations (EUP Guidelines Section 2.7.10(a), (e)-(f), pp. 44-45).

Operational mitigations, including Enhanced Powerline Safety Settings (EPSS), Downed Conductor Detection (DCD), and Public Safety Power Shutoff (PSPS), are reflected in the Baseline rather than evaluated as separate permanent-infrastructure alternatives (Vol. 1, Ch. 3, p. 111; Table 3-9, note (a); Ch. 3, Section D.3.a.11, p. 143). Removal of idle lines and redundant circuit ties is evaluated during the Screen 3 Alternative Mitigation Review (Ch. 3, Section D.3.a.5, p. 131).

PG&E included in the Project Acceptance Framework all permanent wildfire mitigation technologies approved for wide-scale use by PG&E that could be evaluated as alternatives under the EUP Guidelines. Technologies intended to improve the cost or implementation efficiency of an existing mitigation, including Fluid Free Steerable Boring, Native Slurry Backfill, and GLDS/MCDS, are not separate mitigation alternatives (Ch. 3, p. 116). Other technologies, including Continuous Grid Monitoring sensors, Early Fault Detection, are being implemented and evaluated through the 2026-2028 WMP and were not included as separate Alternative Mitigations in the EUP Project Acceptance Framework (EUP Vol. 1, Ch. 3, Section D.2.d, p. 118). REFCL likewise was not included as an Alternative Mitigation because it is not approved for wide-scale deployment by PG&E.

b. In the EUP Screens 2 and 3 processes and analyses, PG&E considered: (1) whether a mitigation was approved for wide-scale use and suitable for deployment in PG&E's service territory (EUP Vol. 1, Ch. 3, Section D.2.b, p. 116); (2) whether it satisfied the comparative-metric requirements in the EUP Guidelines Section 2.7.10 (Ch. 3, Section D.2.a, p. 116; Ch. 7, Section N, pp. 361–362); and (3) whether its wildfire risk reduction, reliability effects, lifecycle costs, and other benefits could be quantified consistently through the WBCA to support comparison across alternatives (Ch. 5, Section C.3.a, pp. 197–199; Attach. B, WP006). These considerations address technical feasibility, wildfire risk reduction, reliability, cost, scalability, and applicability across the EUP Circuit Segment population.

   For alternatives evaluated through the Project Acceptance Framework, wildfire risk reduction is quantified using mitigation effectiveness values and Project Variable Modifiers (Attach. B, WP001; Vol. 1, Table PCS-6), and lifecycle costs and benefits are evaluated through the WBCA. The BCR analysis reflects lifetime capital installation costs and operation and maintenance costs, net of applicable avoided costs or savings.

   The level of feasibility information available differs between Screens 2 and 3. At Screen 2, PG&E applies standardized assumptions to support consistent planning-level comparisons across Eligible Circuit Segments. Screen 2 therefore does not represent a determination that each modeled mitigation could be implemented across the entirety of every Circuit Segment. At Screen 3, PG&E incorporates more detailed project-specific information developed through scoping and evaluates the alternatives using the project configuration and feasibility information available at the time. For example, the Screen 3 hybrid comparison can be updated from the standardized Screen 2 configuration to reflect the actual proportions of undergrounding, overhead hardening, and/or Remote Grid that are feasible for the project. For Remote Grid in particular, feasibility considerations include customer willingness, site availability, land rights, environmental and permitting requirements, and engineering feasibility (Table 3-9, note (b), p. 115). Screen 3 therefore provides the appropriate stage for determining how a mitigation or combination of mitigations may be configured for a particular project.

c. The EUP Guidelines prescribe aboveground hardening using covered conductor, together with associated protective equipment and settings, as Screen 2 Alternative Mitigation 1. PG&E selected 100% overhead hardening for this comparison because overhead hardening is an established PG&E GRC/WMP system-hardening mitigation program that can be evaluated broadly across the Eligible Circuit Segment population and provides a meaningful comparison to undergrounding with respect to

wildfire risk reduction, reliability effects, and lifecycle costs (EUP Vol. 1, Ch. 4, Section D.2, pp. 168–172). PG&E's EUP defines this alternative as the replacement of bare overhead primary conductor and associated framing with covered conductor, together with the applicable system-hardening measures. The EUP Guidelines further require Alternative Mitigation 2 to meet or exceed the risk reduction of Alternative Mitigation 1 and identify line removal with Remote Grid as an example of an eligible mitigation (EUP Guidelines Section 2.7.10(e)-(f); EUP Vol. 1, Ch. 7, Section N, pp. 361-362).

PG&E selected 100% Remote Grid with line removal as Screen 2 Alternative Mitigation 2 because Remote Grid represents a distinct permanent mitigation approach that, where feasible, allows removal of overhead facilities while maintaining electric service through standalone, decentralized utility infrastructure. PG&E did not select a hybrid configuration that included undergrounding as Alternative Mitigation 2 because the EUP Guidelines define an "Alternative Mitigation" as a mitigation strategy other than Undergrounding (EUP Guidelines Appendix A). The Guidelines separately require comparison of 100% Undergrounding against two Alternative Mitigations (EUP Guidelines Section 2.7.10(a), (e)-(f), pp. 44-45). PG&E's prior experience implementing Remote Grid solutions and removing associated overhead facilities provided relevant operational experience with Remote Grid as a permanent mitigation in appropriate circumstances.

PG&E also selected the 100% Remote Grid configuration for Screen 2 to maintain a homogeneous comparison at this preliminary stage. Using homogeneous mitigation design variations provides a logical, consistent, and transparent basis for comparing materially different permanent mitigation strategies across Eligible Circuit Segments (EUP Vol. 1, Table 3-9, p. 115). The Screen 2 Remote Grid comparison does not represent a determination that converting the entirety of each Eligible Circuit Segment to Remote Grid is technically feasible or would be selected for implementation. Rather, it provides a standardized analytical comparison. More granular project configurations, including combinations of undergrounding, overhead hardening, and/or Remote Grid where feasible, can be evaluated in Screen 3 using project-specific scoping information (EUP Vol. 1, Table 3-9, p. 115). Screen 2 BCRs are preliminary Circuit Segment-level comparisons that are refined through Screen 3 as more detailed project-specific scope and feasibility information becomes available (EUP Vol. 1, Ch. 3, p. 110-111).