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Kristin Ralff Douglas
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Office of Energy Infrastructure Safety
715 P Street, 20th Floor
Sacramento, CA 95814

Re: **Pacific Gas and Electric Company's Comments on the Office of Energy Infrastructure Safety's Draft Guidelines for Submission of 10-Year Electric Undergrounding Distribution Infrastructure Plans Pursuant to Senate Bill 884**

Dear Ms. Douglas:

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide the following comments on the draft guidelines (Draft Guidelines) issued by the Office of Energy Infrastructure Safety (Energy Safety) on May 8, 2024, for submission of 10-year electric distribution infrastructure undergrounding plans (EUP) pursuant to Senate Bill 884 (SB 884). The Draft Guidelines establish an undergrounding program framework and direct electrical corporations to provide project details necessary to develop and implement a 10-year undergrounding program. We appreciate the substantial time and effort Energy Safety spent on the Draft Guidelines and the incorporation of feedback from parties. While in general PG&E supports the Draft Guidelines and requests that final guidelines be issued as soon as possible, several items in the Draft Guidelines require modification in order to successfully implement and effectuate the Legislature's intent to establish an expedited distribution undergrounding program.

First, the Draft Guidelines require an EUP to include a substantial amount of information and data. PG&E believes that most of the information required by the Draft Guidelines can be provided to Energy Safety. However, the magnitude and volume of data and modelling required will take an extended period of time for electric corporations to develop and gather to be able to submit an EUP, thereby delaying the feasible timeline to submit an EUP. Additionally, certain requirements exceed SB 884 and will likely require electrical corporations to make significant, time-consuming changes to their current modeling and data capabilities. For example, while PG&E has a limited reliability model that incorporates Public Safety Power Shutoff (PSPS) events, unplanned outages, and certain operational mitigations, the model does not currently include Enhanced Powerline Safety Settings (EPSS). To address the Draft Guidelines requirements, we will need to overhaul our existing reliability model to incorporate EPSS and refine other inputs; even on an expedited basis this may take approximately 12 months. The Draft Guidelines' requirement to perform a reliability ablation study for each circuit segment also represents a new capability that PG&E will have to develop. PG&E estimates that it will take approximately 18 to 24 months to develop this new capability, which is essentially an automated software tool to allow Energy Safety to conduct reliability ablation studies. The requested ablation studies involve a high level of complexity because of the non-linear effects of undergrounding specific circuit segments and because of the dynamic nature of the PG&E's electric system. While the need for data, modeling, and analysis for Energy Safety and stakeholders to understand an electrical corporation's approach to their EUP is certainly valid, requiring data and analysis that goes beyond an electrical corporation's operational needs, and will require substantial time to produce, may hinder the State's goals of expeditiously reducing wildfire risk and enhancing the safety of California's communities. In our comments, PG&E proposes changes to the Draft Guidelines' extensive data requirements that will facilitate electrical corporations' ability to more timely submit EUPs, though it will still take an extended period of time for an electric corporation to develop and gather all of the modeling and data required to submit an EUP. PG&E believes that limiting the data requirements to only what is necessary to evaluate an EUP is consistent with the Legislature's intent for an expedited undergrounding program review process.[1]

Second, the Draft Guidelines ask for some data that is not available in the format requested. For example, the Draft Guidelines ask for data from Geographic Information System (GIS) that PG&E does not maintain in our Electric Distribution (ED) GIS system. To address this data unavailability issue, PG&E recommends that an electrical corporation provide the information in alternative, readily accessible file types. This approach will meet the Draft Guidelines' intent while not requiring electrical corporations to make a significant investment of time and resources to comply.

Third, the Draft Guidelines require further clarification regarding hybrid electric distribution hardening work. In some cases, hardening work on a specific circuit segment may be most effective from both a risk and cost perspective if an electrical corporation is able to perform some undergrounding and some overhead hardening. PG&E refers to this as "hybrid" electric distribution hardening work. The Draft Guidelines do not address this scenario or how hybrid sub-projects should be incorporated into an electrical corporation's EUP. In our comments, we propose changes to the Draft Guidelines to address this scenario.

Finally, PG&E notes that even with the changes proposed in these comments, it is likely that electrical corporations' EUP submissions will not occur until well after the final guidelines are issued given the extensive amount of data and analysis required. For example, PG&E currently anticipates that we will not be able to file our EUP in 2024, as originally intended.

In the remainder of these comments, PG&E:

- <u>Section I</u>: Offers recommendations on where the Draft Guidelines can be improved in terms of clarity, avoiding unnecessary or duplicative filings or requirements, streamlining the amount of data that is needed, and revising or clarifying modeling requirements that are burdensome and/or unclear.

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1 Cal. Pub. Util. Code § 8388.5(a).

- Section II: Requests clarification of certain items and changes to specific governance or procedural requirements such as the timeline for review of an electrical corporation's pre-submission and for responding to a modification notice.

- Section III: Proposes changes to Appendix A.

- Section IV: Proposes changes to Appendix C.

- Section V: Recommends adding a new component to the Draft Guidelines related to hybrid electric distribution hardening work.

- Section VI: Describes the attachments to these comments.

I. SECTION 2 – TECHNICAL GUIDELINES

PG&E has identified areas in Section 2 of the Draft Guidelines where we recommend modifications or changes, including: (1) revisions to the Draft Guidelines to better align the requirements to the data that is available and can be provided by the electrical corporation; (2) streamlining data submissions to minimize administrative burden for Energy Safety, stakeholders, and the electrical corporation; (3) reducing the amount or type of data required from the electrical corporation while not impacting Energy Safety or other stakeholders' ability to evaluate and monitor progress of the EUP; and (4) changes to the definition of certain terms. Specifically, PG&E proposes:

(A) Section 2.4.2: Modifying Screen 2 circuit segment requirements regarding Rapid Earth Fault Current Limit Devices (REFCL);

(B) Section 2.4.3: Removing the requirement to provide an individual Project Reference Sheet for all EUP projects and instead allowing electrical corporations to provide the data in a tabular format;

(C) Section 2.4.5.2: Reducing information requirements regarding non-EUP projects;

(D) Section 2.5.1: Revising modeling requirements from 60 years to 55 years;

(E) Section 2.7.5 – Core Capability 1: (1) Apportioning risk and reliability benefits across the sub-projects in a circuit segment for the Separate Analysis; (2) Excluding the requirements for a reliability Ablation Study at the time of EUP submission and instead allowing electrical corporations additional time to develop solutions to address this concept; and (3) Allowing electrical corporations to model outages and reliability improvements based on recent historical data and not forecast data;

(F) Section 2.7.5 – Core Capability 4: Replacing the term "discount rate sums" with the term "discount rate" for clarity and consistency with other regulatory proceedings;

(G) Section 2.7.5.1: Modifying data sharing requirements to take into consideration potential contractual limitations on sharing third-party proprietary data;

(H) Section 2.7.6: Modifying the information requirements for Project Variable Modifiers to allow for a narrative description of risk model changes;

(I) Section 2.7.9: Revising the definition of High-Risk Threshold to reflect the Normalized-Overall Utility Risk level above which a circuit segment is considered eligible for examination for expedited undergrounding;

(J) Section 2.8: Streamlining and coordinating reporting metrics with the California Public Utilities Commission (CPUC) reporting metrics; and,

(K) Section 2.8.7.2: Limiting the required information about third-party equipment on poles to situations where the electrical corporation has a lease or agreement with the owner of that equipment, or the information is otherwise available to the electrical corporation.

A. Section 2.4.2 - Screen 2: Project Information and Alternative Mitigation Comparison

Section 2.4.2 describes the Screen 2 requirements for comparing undergrounding to alternative mitigations at the circuit segment level in order "to determine which Eligible Circuit Segments can be treated as Undergrounding Projects."[2] SB 884 requires that an EUP include, at a minimum, a comparison of undergrounding versus alternative mitigation strategies such as covered conductor and REFCL.[3] REFCL technology mitigates ignitions from line-to-ground faults such as wire down or tree contacts and is applied at the substation level, not the circuit segment level. However, the Draft Guidelines require that Screen 2, including an analysis of REFCL, be performed at a circuit segment level. Because REFCL occurs at the substation level, it cannot be compared to other mitigations at the circuit segment level as required by the Draft

[2] Draft Guidelines at 7.

[3] Cal. Pub. Util. Code § 8388.5(c)(4).

Guidelines. PG&E recommends modifying the final guidelines to allow an electrical corporation to provide an alternatives analysis for REFCL, or other mitigations as necessary, at a different level of granularity than the circuit segment level, where appropriate.

B. Section 2.4.3 – Screen 3: Project Risk Analysis

Section 2.4.3 introduces the Project Risk Analysis and provides that a Project Reference Sheet be prepared for "each project under consideration under Screen 3 (Project Risk Analysis)."[4] Additional information about completing the Project Reference Sheet is provided in Section 2.8.7.2 (Project Reference Sheet Overview) and Appendix E (Project Reference Sheet). The Project Reference Sheet contains a narrative description of the project plus a substantial amount of information and metrics including: (1) detailed project information (e.g. risk rank, risk score, outage likelihood, etc.); (2) a timeline segregated into individual project phases (e.g. scoping, permitting, construction, etc.); (3) a comparison of various costs and benefits (e.g. safety benefits, financial benefits, risk reduction, etc.) of the proposed undergrounding project and at least two alternatives; (4) comparative risk metrics for the proposed project plus a minimum of two alternatives; and (5) any additional metrics.

At the May 22, 2024, Question and Answer session, Energy Safety clarified that a Project Reference Sheet will be required for all EUP projects considered under Screen 3.[5] PG&E envisions including hundreds of individual projects as part of our 10-year EUP. Given the volume and type of data that PG&E will provide for each proposed project as required by the Draft Guidelines, we recommend the final guidelines be modified to remove the requirement for providing an individual Project Reference Sheet for each project and instead allowing the electrical corporation to provide the required information in a tabular file to enable easy project comparison and data analysis and minimize administrative burden for Energy Safety, stakeholders, and the electrical corporations.

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[4] Draft Guidelines at 8.

[5] Draft Guidelines at 9.

C. Section 2.4.5.2 – Information on Non-EUP Projects

Section 2.4.5.2 requires an electrical corporation to provide information on any distribution undergrounding project that is not included in the 10-year EUP but that is funded or in the planning/construction phases. Table 1, Circuit Segment Information Lists, instruct the electrical corporation to provide information about these non-EUP projects as described in Appendix C-1. Appendix C-1 lists 13 different data tables with multiple rows of information included in each table. The non-EUP distribution undergrounding projects that PG&E will likely conduct over the 10-year EUP include Rule 20A projects or other projects funded through the General Rate Case (GRC). These non-EUP projects will have undergone review in the appropriate regulatory proceeding before funding has been approved.

For example, Rule 20A projects are considered based on avoiding or eliminating a heavy concentration of overhead electric facilities, the street or right-of-way adjoins or passes through a civic area or public recreation area or an area of unusual scenic interest or other similar criteria. It would be unreasonable for an electrical corporation to be required to provide detailed risk information about a Rule 20A project, especially because these projects are not a part of the EUP and may not be in High Fire Threat District (HFTD) areas.

At the May 22, 2024, Question and Answer session, Energy Safety indicated that electrical corporations are required to include non-EUP projects on Table C.1 (Example Plan Table Construction and Data Requirements) and on Table C.5 (Circuit Segment Identification Table and Data Requirements).[6] We appreciate the clarification that electrical corporations do not need to include non-EUP projects on all the Appendix C reports. Based on the discussion above, we recommend that the requirements for non-EUP projects in the final guidelines be revised to include limited, relevant data fields from the tables in Appendix C-1 instead of requiring all of the information requested in Table C.1 and Table C.5. Table 1 below is PG&E's

[6] May 22, 2024, Energy Safety Question and Answer Session, slide number 11.

recommended list of relevant information for non-EUP distribution undergrounding projects to be used in the final guidelines.

Table 1 – Recommended Information for Non-EUP Distribution Undergrounding Projects

Column Name	Field Description	Data Type	Appendix C-1 Source Table
utility_name	EC abbreviation (PG&E, SDG&E, SCE)	NVARCHAR(32)	C.1
project_id	A unique value identifying the project	INT	C.5
external_funding	If undergrounding of this Circuit Segment is already funded through the General Rate Case or other funding, list that program here.	TEXT	C.5
risk_model_version_id	A unique value identifying the version of the risk model used to select the project		New data
circuit_segment_length	The length of the circuit segment	REAL	C.5
overall_utility_risk_rank_system	Rank of the risk within the system	INT	C.6
cpuc_project_code[(a)]	A code that identifies a grouping of undergrounding projects associated with certain activity: 08W – System Hardening Wildfire Resiliency Projects; 3UG – Targeted Undergrounding; 95F Electric Distribution Major Emergency	NVARCHAR(255)	C.8
fips_county_codes	A Federal Information Processing Standards code used to uniquely identify U.S. counties and their equivalents.	JSON	C.8
Hftd	An integer value representing the CPUC High Fire Threat District (HFTD) area.	NVARCHAR(32)	C.8
Rebuild	Value signifying whether a project is in a Wildfire Rebuild Area or not.	BOOLEAN	C.8

Column Name	Field Description	Data Type	Appendix C-1 Source Table
status_current	Current project status: scoping; design; permitting; ready for construction; construction in projects; construction completed; overhead de-energization.	NVARCHAR(255)	C.11
(a) Note, the activity codes provided in Table C.8 of the draft guidelines are internal PG&E Maintenance Activity Type (MAT) codes, not CPUC project codes as listed in the "Column Name" field in Table C.8.			

D. Section 2.5.1 – Project Timelines and Targets

Section 2.5.1 requires an electrical corporation to provide a Plan Objective Table with information about the timelines for completion, start and end dates, risk reduction, and other information. The Draft Guidelines define the expected lifetime of the infrastructure as 60 years.[7] PG&E assumes that the 60 years referenced in the Draft Guidelines is the 50-year asset life plus the 10 years of the undergrounding program.

PG&E defines the life of an underground asset as 55 years[8]. The life of an undergrounding project asset starts with energization of the underground distribution line and continues for the next 55 years. Cumulative ignition risk reduction and cumulative outage reduction for an underground line energized in year 1 of the EUP would start year 1 and run through year 56. An underground line energized in year 2 of the EUP modeling would start year 2 and run through year 57. Underground lines energized in year 10 of the EUP would be modeled starting in year 10 and finishing in year 65. We would not model all infrastructure for 60 years, rather for the 55-year life of the asset based on the energization date.

PG&E recommends that the final guidelines be revised to: (1) define the expected lifetime of the underground asset as 55 years; (2) state that modeling requirements are 55 years from the date of energization. Alternatively, the final guidelines could provide that each

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7 Draft Guidelines at 13.

8 Adopted asset life in CPUC Decision (D.) 23-11-069 (PG&E's 2023 GRC).

electrical corporation submitting an EUP define the expected asset life of the assets being installed and model accordingly.

E. Section 2.7.5 – Required Core Capabilities for Risk Modeling Methodology (Core Capability 1: Project-Level Risk Analysis)

Section 2.7.5, Core Capability 1, requires an electrical corporation to demonstrate that its modeling framework can analyze project-level risk reduction both separately and collectively by conducting a Collective Analysis, a Separate Analysis, and an Ablation Analysis. PG&E identified two concerns related to the Core Capability 1 requirements: (1) conducting a Separate Analysis for each project; (2) the Ablation Analysis; and (3) enhanced Reliability modeling.

1. Conducting a Project-Level Separate Analysis

PG&E will perform our project work at a "sub-circuit segment level"—circuit segments that are identified for undergrounding will be divided into smaller, individual projects based on design, construction, permitting, or other concerns. Ultimately, the entire circuit segment will be hardened through undergrounding or a "hybrid" approach combining undergrounding and installation of covered conductor. To meet the requirement for conducting separate, project-level risk analysis, PG&E proposes that the risk reduction and reliability improvements for a circuit segment based on risk model output be normalized and apportioned across the circuit segment for the purposes of sub-project reporting. This apportionment would be done outside of the risk model.

For example, the risk model indicates that after hardening is complete, Circuit Segment A will reduce ignition risk by 20 points and improve reliability by 40 points. Circuit Segment A is divided into 10 hardening sub-projects, and PG&E apportions the decrease in ignition risk value across the 10 sub-projects that totals to 20 points and apportions the reliability improvement value across the 10 sub-projects that totals to 40 points. As each sub-project is completed, PG&E reports the decrease in ignition risk and improved reliability for the individual sub-project. When the entire circuit segment is completed, PG&E will have reduced ignition risk by 20 points and improved reliability by 40 points. PG&E recommends that the final guidelines state that an electrical corporation can conduct a Separate Analysis at the project-level (referred to by PG&E as the sub-project level) by apportioning the risk reduction and reliability improvements across a circuit segment and that the apportionment can be done outside of the risk model.

2. Ablation Analysis

The Draft Guidelines define Ablation Analysis as the effects of a portfolio if a single project is taken out of the portfolio and it reports these effects at both the circuit and portfolio level. Ablation analysis is required for projects on the Confirmed Project list (Screen 3). PG&E can conduct an ablation study for ignition risk but does not currently have the tools or models to conduct ablation analysis for reliability projects. We are working on ways to address the requirements for a reliability ablation study, but at this time we do not believe we can meet the requirements in the Draft Guidelines in order to timely submit a 10-year EUP. PG&E recommends that the final guidelines exclude the requirements for a reliability ablation study at the time of submission and allow electrical corporations additional time to develop solutions and a timeline to address this requirement, with updates on progress towards this goal communicated through the progress reports.

3. Enhanced Reliability Modeling

The Draft Guidelines require an electrical corporation to model outage or reliability risk at a level similar to wildfire risk modeling, which is currently beyond the maturity level of PG&E, and potentially other electrical corporations. While wildfire risk modeling has been matured to the current level over several years of iteration including regulator feedback and partnership with external experts, reliability improvements and outage performance have largely been assessed through analysis of empirical data (recent historical outages on those circuit segments). Overhauling an electrical corporation's reliability risk modeling to achieve a similar level of probabilistic prediction as wildfire risk modeling and incorporating all outage drivers, including EPSS, is possible, but will take time to develop; even on an expedited basis this may take up to 12 months. Given that recent historical outage information provides a reasonable approximation for the likely outputs from a probabilistic outage risk model and is more readily available for some factors, like EPSS, to support a timely EUP filing, PG&E recommends that the Draft Guidelines be revised to allow electrical corporations to model outages and reliability improvements in their EUPs based on their existing reliability models and recent historical data and not forecast data. This would allow electrical corporations to file an EUP more timely and have the time to develop a comprehensive reliability risk model to inform future project selection through the established screens.

F. Section 2.7.5 – Required Core Capabilities for Risk Modeling Methodology (Core Capability 4: Approximating Future Risks and Accumulating of Ignition Risk and Outage Program Risk over Time)

Section 2.7.5, Core Capability 4, requires an electrical corporation to list any discount rate sums employed in the calculation of key decision-making metrics (KDMMs) and explain their origin.[9] Additionally, if the discount rate sums change over time, the electrical corporation must explain how and why the changes occurred in line with the Risk-Based Decision-Making Framework Proceeding (Rulemaking R. 20-07-013). The term "discount rate" is a recognized term used in both regulatory proceedings and finance activities whereas the term "discount rate sum" generally is not. To align to the terminology used in CPUC Rulemaking (R.) 20-07-013 and finance activities, PG&E recommends slightly modifying this requirement in the final guidelines by removing the word "sum" from the phrase "discount rate sum" everywhere it appears.

G. Section 2.7.5.1 – System Inputs and Considerations

Section 2.7.5.1 states that an electrical corporation must provide a comprehensive list of all model inputs used to compute every metric in its risk model landscape including all precursor calculations and any other metric reported in the Project Reference Sheet or Portfolio Coversheet. Providing a comprehensive list of model inputs to compute every metric and all

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9 Draft Guidelines at 23.

precursor calculations would only be needed to recreate our risk models but is unnecessary to assess the validity of those risk models.

During the May 22, 2024, Question and Answer session Energy Safety indicated that it will not require a comprehensive list of all model inputs and every precursor calculation. Therefore, PG&E recommends that the final guidelines be modified to require a narrative summary describing the inputs used to calculate the various metrics. This higher-level information will provide a sufficient understanding of the electrical corporation's risk model landscape for Energy Safety and stakeholder to assess the validity of those models and can be supplemented through data requests if additional, specific information is needed.

In addition, PG&E's risk models also include certain third-party proprietary business information. PG&E and other electrical corporations may be contractually prohibited from sharing third-party proprietary information, or there may be certain contractual conditions which limit how the information can be shared. PG&E recommends that the final guidelines be revised to indicate that third-party proprietary modeling information be provided where needed, and if possible, to Energy Safety on a confidential basis subject to the terms of any contractual limitations on sharing such information.

H. Section 2.7.6 – Project Variable Modifiers (PVMs)

Section 2.7.6 requires the electrical corporation to list its Project Variable Modifiers (PVMs), explain how the PVMs were calculated, and if and how their use varies in different evaluations of the Model Risk Landscape. PVMs are changes made to variables in the electrical corporation's Risk Modeling Methodology to evaluate the effectiveness of a given project or projects. PG&E interprets PVMs as mitigation effectiveness assessments (e.g. undergrounding is 97.7 percent effective at reducing ignition risk), which may include the use of empirical data or, as the Draft Guidelines suggest, adjustments to risk model methodology. However, it is unclear if our interpretation aligns with the Draft Guidelines or if Energy Safety is looking for more detailed information that PG&E may or may not be able to provide. Therefore, PG&E

recommends that the final guidelines be modified to direct electrical corporations to provide a more general, narrative description of changes to effectiveness factors, the reasons for the changes, and the result of the changes on the alternative mitigation analysis.

I. Section 2.7.9 – System Inputs and Considerations

Section 2.7.9 requires an electrical corporation to establish and explain Project Thresholds to establish the need for mitigation on a circuit segment. The Project Thresholds are made up of four individual thresholds including the "High-Risk Threshold." The Draft Guidelines define the High-Risk Threshold as the Overall Utility Risk level above which a circuit segment is considered eligible for examination for expedited undergrounding.

PG&E agrees that screening circuit segments for expedited undergrounding based on a High-Risk Threshold is a reasonable approach. However, because the length of each circuit segment length can vary dramatically, PG&E interprets this threshold as being based on a normalized unit of measure across each circuit segment, such as per mile. For example, in comparing a high risk, short circuit segment consisting of 1 span of conductor to a low risk, long circuit segment consisting of 100 spans of conductor, the shorter circuit segment would have a low risk score under the Overall Utility Risk calculation method but a high risk score under a Normalized Overall Utility Risk calculation method. Conversely, the low risk, long circuit segment would have a high risk score under the Overall Utility Risk calculation method but a low risk score under a Normalized Overall Utility Risk calculation method. The Normalized Overall Utility Risk calculation method allows an electrical corporation to identify the highest risk circuit segments regardless of length. PG&E recommends that the definition of High-Risk Threshold be revised in the final guidelines to reflect the Normalized-Overall Utility Risk level above which a circuit segment is considered eligible for examination for expedited undergrounding.

J. Section 2.8 – Reporting Metrics

Section 2.8. contains detailed instructions on how an electrical corporation will report on its risk modeling methodology, its undergrounding projects, the development of new models, and non-model-based projections. An electrical corporation will also be required to report similar information to the CPUC as part of the 10-year EUP cost recovery process. PG&E recommends that Energy Safety and the CPUC reporting requirements be streamlined and consistent wherever possible.

K. Section 2.8.7.2 – Project Reference Sheet Overview

Section 2.8.7.2 lists the information that an electrical corporation must provide on the Project Reference Sheet it develops for each undergrounding project. The electrical corporation is required to indicate whether any communications companies or other third party has equipment on the poles where the circuit is currently located. PG&E can provide information about the third parties or communications companies with whom PG&E has a lease or agreement but cannot provide information about equipment on poles where the communications company or third party has a lease or agreement with another entity. PG&E recommends that the final guidelines be modified to require information about third-party equipment on poles only when the electrical corporation has a lease or agreement with the owner of that equipment, or the information is otherwise available to the electrical corporation.

II. SECTION 3 – PROCESS AND EVALUATION

PG&E identified three governance/procedural issues in the Draft Guidelines that we address in these comments:

(A) Section 3.1.2: Specifying the maximum duration of the pre-submission completeness check and submission and availability of the pre-submission EUP to Energy Safety;

(B) Section 3.5.2: Developing a schedule for an electrical corporation's response to a Modification Notice; and

(C) Section 3.7: Revising the timing for responding to stakeholder data requests.

A. Section 3.1.2 – Pre-Submission Review Process

Section 3.1.2 of the Draft Guidelines outlines the Pre-Submission Review Process but does not identify the duration of this pre-submission review. In our Comments on Energy Safety's working group meetings on the development of the draft guidelines,[10] we noted that the CPUC has proposed that it will perform a completeness review of an electrical corporation's cost recovery application within 10 business days. At the May 22, 2024, Question and Answer session, Energy Safety indicated that the pre-submission could be completed in 10 days but did not commit to a maximum length for pre-submission review. PG&E recommends revising the final guidelines to state that the pre-submission review will be completed in 10 days.

Section 3.1.2 of the Pre-Submission Review Process does not specify how the pre-submission EUP should transmitted to Energy Safety. PG&E recommends that the pre-submission EUP be transmitted to Energy Safety as a confidential document. Consistent with Section 3.1.2, once Energy Safety confirms the pre-submission is complete it will open a docket for the EUP, and the electrical corporation will then submit the final EUP on the docket for Energy Safety and public evaluation.

B. Section 3.5.2 – Modification Notice Process

Section 3.5.2 of the Draft Guidelines outlines the process for electrical corporations to respond to a Modification Notice issued by Energy Safety. The Draft Guidelines note that Energy Safety will include a schedule by which the electrical corporation must submit its Modification Notice Response. PG&E recommends that the final guidelines be modified to allow the electrical corporation to work with Energy Safety to develop a reasonable schedule for responding to a Modification Notice depending on the type and number of issues that must be addressed and allowing time to ensure the updated document(s) meet the accessibility requirements set forth in the Draft Guidelines.

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[10] PG&E's Comments on the Office of Energy Infrastructure Safety's Working Group Meetings on the Development of Guidelines for Submission of 10-Year Electric Undergrounding Distribution Infrastructure Plans Pursuant to Senate Bill 884, p. 13.

C. Section 3.7.2.2 – Data Request Process for Data Requests from Stakeholders

Section 3.7.1 of the Draft Guidelines provides for a three-business day response period for data requests from Energy Safety and Section 3.7.2.2 provides for a three-day response period for data requests from other stakeholders. PG&E agrees that the three-day response period for data requests from Energy Safety (with the allowance for approved extensions) is reasonable given the responsibility of Energy Safety to ultimately approve the EUPs, but PG&E recommends that in the final guidelines the response period for data requests from stakeholders be increased to five business days. PG&E wants to provide the information necessary for stakeholders to fully evaluate and understand our EUP. However, given the volume of data requests electrical corporations will likely receive from numerous stakeholders, responding to these requests requires significant time from a limited population of subject matter experts and thus a five-business day turnaround for stakeholder data requests is reasonable. The five-business day data response timeline is also consistent with the timeline set forth in the CPUC's Guidelines for review of an electrical corporation's EUP after approval by Energy Safety.[11]

III. APPENDIX A – DEFINITIONS

PG&E is recommending changes to certain definitions included in the Draft Guidelines as they relate to the recommendations we discuss herein. Our proposed modifications are shown in Attachments 1 and 2 to these comments (see Section VI below).

IV. APPENDIX C – DATA ORGANIZATION AND STRUCTURE

PG&E is recommending changes to certain requirements in Appendix C. Our recommendations are focused on modifications or additions to file types that an electrical corporation will provide to Energy Safety and excluding certain confidential data from the information provided, including:

(A) Appendix C.4: Providing information about undergrounding projects in geospatial files with maps of the planned undergrounding work in either GIS

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11 Resolution SPD-15, Attachment 1, p. 5.

or other file type, like KMZ, or combinations of file types, that are readily available;

(B) Appendices C.4.1, C.4.2, C.4.3 and C.4.4: Modifying the Draft Guidelines' requirements to allow an electrical corporation to provide GIS data, or other file types, in order to satisfy the different requirements; and

(C) Appendix C.4.2: Modifying the Draft Guidelines' requirements to allow electrical corporations to provide asset data that is readily available in GIS and to exclude data or combinations of data that would be considered confidential.

A. Appendix C.4 – GIS Data Schema

Appendix C.4 sets forth the requirements for how an electrical corporation must report its geospatial data. PG&E's overhead and underground assets appear in our GIS system, and we can provide this GIS information to Energy Safety. However, from the time an overhead circuit segment is selected for undergrounding through the completion of the undergrounding project (e.g., during scoping, designing, permitting, and construction), we manage our work using KMZ files. PG&E's ED GIS system is based on current system configurations and would require significant new technology, governance, and safety requirements and would represent a significant change to how we operate our business.

A KMZ file is viewable in various, readily available GIS applications including Google Earth. KMZ files provide similar information as a GIS file, and we currently share planned undergrounding information using KMZ files with local governments and other interested parties through our community wildfire resource program. PG&E recommends that the final guidelines be revised to allow electrical corporations to provide information about their undergrounding projects in geospatial files with maps of the planned undergrounding work in either GIS or another file type, like KMZ, that is readily available and will provide the information Energy Safety and stakeholders need to review undergrounding project progress.

B. Appendix C.4.1 – Overhead Conductor (Line Feature Class); Appendix C.4.2 – Overhead Assets (Point Feature Class); Appendix C.4.3 – Underground Alignment (Line Feature Class); and Appendix C.4.4 – Underground Asset Points (Point Feature Class)

Appendices C.4.1 through C.4.4 describe the four different geospatial data reports electrical corporations must provide to Energy Safety related to overhead and underground assets. PG&E's concerns related to these four appendices are also related to requirements in Section 2.8.2 and Section 2.8.3.

Section 2.8.2 states that an electrical corporation must submit certain JSON data in each Progress Report, starting with Progress Report 0. Details about these requirements are provided in other sections of the guidelines (Section 2.8.5.2, Section 3.9.1, Section 3.11, and Appendix C.2). Section 2.8.3 requires the electrical corporation to report additional modeling and project-level data through a geodatabase submission. This information will identify isolatable Circuit Segments, Undergrounding Projects, and overhead lines that will be deenergized after completion of projects and critical pieces of infrastructure equipment. Details are provided in Appendix C.3

To limit redundancy in these comments, we address all our concerns about the Draft Guideline requirements identified above in the paragraphs below followed by our proposed recommendation. Each of the four appendices require information that is not captured in PG&E's GIS system. PG&E's ED GIS system is our system of record for electric asset inventory, spatial location, electrical connectivity, and attribute data. Additional information is stored in supplemental databases, but our GIS system does not include information that is unique to all the on-going ED projects and programs. For example, the Draft Guidelines require information for the EUP, such as "portfolio_id" (a unique value identified the 10-year EUP portfolio), that is not and will not be captured in GIS. Additionally, the appendices require an electrical corporation to include a "segment_id" in the individual geospatial data reports. The field segment_id is defined as:

> Unique ID of circuit segment. Must be a unique value that identifies this portion of the circuit and a traceable stable ID within the electrical corporation's operations/processes. This field is required. A segment may be anything more granular than a circuit, including a single span.

While the Draft Guidelines require a unique ID for a circuit segment, PG&E does not include circuit segment data in GIS. Any line or circuit segment designations are for internal use only and are not centrally managed or governed in GIS.

The definition for segment_id states that the identified portion of the circuit should be traceable and stable within the electrical corporation's operations/processes. However, PG&E's grid is dynamic. Circuit segments and/or circuit protection zones change regularly and therefore there are no static circuit protection zones. Different lines of business within PG&E define line segments or circuit protection zones differently based on their processes or operations. As an example, PG&E's risk team identifies circuit protection zones in the risk models whereas operational processes such as vegetation management and EPSS segment distribution lines differently to align to their work activities.

Because the information required by the Draft Guidelines does not all exist in GIS, PG&E recommends that the final guidelines be modified to allow an electrical corporation to provide GIS data, or other file types, in order to satisfy the different requirements. PG&E could provide certain information from GIS (*e.g.*, circuit identification, line class, asset information) and other information from risk modeling files (*e.g.*, circuit segment and more detailed project information). The combination of files will allow Energy Safety and stakeholders to track and monitor PG&E's progress and hold PG&E accountable for the completing the work included in the EUP.

C. Appendix C.4.2 – Overhead Assets (Point Feature Class)

Appendix C.4.2 requires an electrical corporation to report on some overhead assets other than conductor identified for undergrounding (Field Name: asset_type). The types of assets represented include capacitor bank, fuses, switchgears, and transformers. PG&E can provide the asset information tracked in GIS though not all asset information may be available.

Additionally, the level of asset data requested is extremely detailed and, when combined with other information required by the Draft Guidelines, will result in the critical infrastructure information being considered confidential that cannot be posted on a public website. Because managing multiple versions of confidential and non-confidential files is administratively burdensome, PG&E recommends that the final guidelines be revised to allow electrical corporations to provide asset data that is readily available in GIS and to exclude data or combinations of data that would be considered confidential.

V. RECOMMENDED ADDITIONS TO THE DRAFT 10-YEAR ELECTRICAL UNDERGROUNDING PLAN GUIDELINES

SB 884 sets forth the general requirements for large electrical corporations to prepare and submit an expedited utility distribution infrastructure program to Energy Safety for review and approval. After the EUP is approved by Energy Safety, an electrical corporation submits an application for review and conditional approval of the plan's costs to the CPUC.[12] SB 884 is focused on relocating overhead conductor underground to reduce wildfire risk and improve reliability.

As we have evaluated the requirements in the Draft Guidelines and analyzed undergrounding work already completed, PG&E has determined that there will be locations on our system where it is most reasonable to harden a circuit segment through a combination of undergrounding and overhead hardening with covered conductor. Certain projects could also include line removal and remote grid. As discussed below, this hybrid approach—a circuit segment that is hardened using a combination of covered conductor, undergrounding, and/or line removal with remote grid (referred to herein as "hybrid distribution hardening") -- can help reduce project costs, increase risk reduction, and improve reliability.

For the purposes of the EUP, PG&E recommends defining hybrid electric distribution hardening as a sub-project that consists of at least 80 percent undergrounding and up to 20 percent overhead covered conductor or line removal. When deploying a robust mitigation

12 California Public Utilities Code Section 8388.5.

selection process within circuit segments, there are likely to be mixed hardening solutions (a mix of overhead, underground, and line removal) deployed for many circuit segments, with some having 80 percent or more undergrounding and others having less than 80 percent undergrounding. Understanding the intention of the EUPs and SB 884 to be primarily focused on undergrounding, PG&E believes up to 20 percent non-undergrounding work to be a reasonable proportion of a project for it to still be considered principally an "undergrounding" project and therefore subject to an electrical corporation's EUP. For circuit segments where less than 80 percent of the circuit segment has been identified for undergrounding, the sub-projects will be segregated with the undergrounding sub-project presented in the EUP and non-undergrounding portions captured in a different regulatory process (e.g. the utility's GRC).

PG&E requests that the final guidelines expand the scope of the 10-year EUP to include hybrid distribution hardening (made up of 80% or greater undergrounding). The costs for hybrid distribution hardening would then be included in an electrical corporation's application for EUP program costs filed with the CPUC. By including hybrid distribution hardening in the 10-year EUP, the electrical corporation would no longer request this work or these costs in its GRC. Having the entire scope of work and costs for hybrid distribution hardening work for a circuit segment in one proceeding, instead of divided between an EUP and GRC, is more efficient for regulators and stakeholders, provides a more comprehensive view of the work the electrical corporation is proposing, and solves the issue of mismatched timing and approvals among cases for sub-projects within a circuit segment.

For example, as it stands today, if an electrical corporation proposed hybrid distribution hardening on 20 circuit segments, the undergrounding portion of that work would be included in the EUP, and the covered conductor or line removal portions of those circuit segments or sub-project would be forecast in the GRC. If the costs for the undergrounding work were approved before the GRC, the electrical corporation would underground a portion of 20 circuit segments but would not be able to complete the overhead hardening or remote grid line removal portions of these circuit segments until the non-undergrounding work is approved in the GRC. Delaying work on portions of the circuit segments until a second, separate regulatory process is completed will result in delayed wildfire risk reduction and fails to improve reliability as much as hardening the entire circuit segment in a timely manner. Working on the same circuit segment at two different times is less efficient, more disruptive to customers, and increases costs. If all the hybrid distribution hardening work is included in the EUP, the electrical corporation could underground and perform other, cost-effective system hardening (*e.g.*, covered conductor) on the 20 circuit segments at the same time. Being able to propose and recover costs for hybrid distribution hardening in one proceeding encourages electrical corporations to employ a hybrid approach, where appropriate.

PG&E recommends that the final guidelines be modified to include "hybrid distribution hardening" as a reasonable, acceptable approach to distribution system hardening that is covered by the 10-year EUP guidelines.

VI. ATTACHMENTS TO PG&E'S COMMENTS ON THE DRAFT GUIDELINES

PG&E has prepared two attachments to our comments: (1) Attachment 1 is list of recommended revisions to the Draft Guidelines; and (2) Attachment 2 is a table showing our recommended changes to the language in the Draft Guidelines. Attachment 2 aligns to the recommendations made herein and represents our suggested edits to the final guidelines.

VII. CONCLUSION

PG&E appreciates the opportunity to provide these comments and looks forward to continuing to partner with Energy Safety and stakeholders on this important work. If you have any questions, please do not hesitate to contact the undersigned at Megan.Ardell@pge.com.

Very truly yours,

/s/ Megan Ardell

Megan Ardell