PACIFIC GAS AND ELECTRIC COMPANY
PG&E Ref. DRU13015
Data Request OEIS
Requester Event Ref. No. Energy Safety-DR-EUP-24-01
Requester DR No. Underground Project Tracking

Requester: Brant, Simone
Request Date: January 30, 2024
Response Date: February 13, 2024

Question No. 001:

Undergrounding Project Phases

a) How do you define an undergrounding project?
b) What are the specific phases of an undergrounding project that you track? Are they aligned with the five phases listed in the CPUC SB 884 staff proposal (Scoping, Designing/Estimating, Permitting/Dependency, Ready for Construction, and Construction)?
c) At what phase are you able to make comparisons with other mitigation types? How do you determine which alternative mitigations to include in the comparison?
d) At what phase can you develop firm cost estimates?
e) At what phase do you consider the project to be a scoped undergrounding project?
f) At what phase are project ID numbers assigned? At what phase are sub-project/job ID numbers assigned?
g) At what phase are precise GIS data available for the undergrounded line? What types of organizations/community partners is this information shared with and when?

Response to Question No. 001 Response No. 001:

PG&E responds to each sub-part of Question 001 below.

a) *Definition of an undergrounding project.* As stated in PG&E's Comments on CPUC Safety Policy Division staff's original proposed guidelines for the SB 884 program (September 27, 2023), PG&E defines a "project" at the circuit segment level (also referred to as circuit protection zone (CPZ)) because our current risk model measures risk at the circuit segment level and does not have more granular risk detail. When projects are scoped and planned for near-term completion (generally within 3 – 4 years), we create sub-projects, or jobs, which will reflect portions of a CPZ. PG&E identifies jobs based on mileage, diversity of risk ranking, dependencies (e.g., easements, environmental permitting issues) and constructability. As the risk models are periodically updated and released, projects may be added to the workplan, reprioritized, or removed.

b) *Phases of undergrounding project.* We track the following phases of an undergrounding project: scoping, design/estimating, permitting/dependency, construction (i.e., construction scheduling, civil construction and electric construction), and post-construction (this phase includes closed projects). These project phases are similar to the phases listed in Appendix 1 to the CPUC Staff Proposal for the SB 884 Program attached to CPUC Resolution SPD-15.

c) *Timing of comparison with other mitigations and alternatives compared.* During the scoping phase, we make comparisons between undergrounding and other mitigation types; this comparison is finalized at the end of scoping. We compare alternative mitigations that are feasible to implement in the location identified as high-risk. For example, where viable, line removal with or without remote grid is considered prior to undergrounding or overhead hardening. Both undergrounding and overhead hardening are considered where both are feasible.

d) *Timing of cost estimate development.* Cost estimates are considered "firm" at the end of the estimating/dependency phase. Cost estimates may continue to be refined through the construction phase. Once civil construction is complete with conduit and boxes installed, then electric construction resources pull the cable through the conduit, splice segments together and re-connect customers to the new underground system. At this phase, our understanding of the cost associated with the project is more fully developed. Costs continue to be accrued as the project closes out. Costs are final once closeout is complete.

e) *Phase at which project is considered scoped.* We officially consider projects to be scoped at the end of the scoping phase. During the detailed scoping process, the scoping lead and project manager, with support from functional groups (i.e., Land, Environmental, Planning, Estimating, Permitting, Construction), will review the project scope that was identified during the high-level feasibility assessment process. The scope review entails both a desktop review and a field visit. As part of the detailed scoping process, the scoped circuits will be segmented to breakdown the work into manageable sub-projects. Following the detailed scoping process, a Design Basis Memo (DBM) is developed. The DBM is the conclusion of the process of defining the scope and triggers the readiness for the next step of detailing the project design through the Design Phase.

f) *Phase at which project ID numbers are assigned.* Project ID numbers and sub-project/job ID numbers are assigned during the scoping phase.

g) *Phase at which precise GIS data are available.* Precise GIS data are available during post-construction, once mapping is complete. General location data may be available as early as the estimating phase, but these data are not precise and reflect only expected location detail until after construction is complete and project closure has progressed through mapping. We share preliminary, expected location GIS data with community organizations.

<u>Question No. 002:</u>

Current Projects

a) How many undergrounding projects do you currently have in each of the project phases described in Q01?
b) How many project miles fall under each category?
c) Are some projects comprised of multiple circuit segments or all they all individual segments? If projects are comprised of multiple segments, must those segments be continuous?

Response to Question No. 002 Response No. 001:

We respond to this question by sharing data on all sub-projects from 2018 forward that include undergrounding miles in scope (see response to Question 001 subpart (a) that defines a sub-project). This includes work that contributes toward PG&E's 2023 – 2025 WMP GH-01 target that was performed under MAT codes 08W and 3UG, as well as other MAT codes. The data shown below exclude Butte/Community Rebuild sub-projects and miles. However, if this data set would be helpful, we can provide it.

Data used in this analysis were refreshed as of February 7, 2024.

a) *Sub-Projects by phase.* Table 1 shows the number of sub-projects in each of the phases described in the response to Question 001, sub-part (b).
b) *Miles by phase.* Table 1 shows the number of miles associated with sub-projects in each of the phases described in the response to Question 001, sub-part (b).

Table 1. Number of Undergrounding Sub-Projects and Miles in Each Sub-Project Phase as of February 7, 2024

Phase	SAP Status Code(s)	Number of Sub-Projects	Number of Miles Associated with Sub-Projects in Each Phase[1]
Scoping	UNSE	182	614.5
Design/estimating	ESTS, ADER, APPR	189	214.7
Permitting/dependencies	PEND	90	172.8
Construction	UNSC, CONS	154	278.7
Post-construction	DOCC, MAPP, FICL, CLSD	337	290.5

[1] This column includes miles associated with the sub-projects in the "number of sub-projects" column. For example, the number of miles in the "Construction" row shows the number of miles associated with the 154 sub-projects in the construction phases (with SAP status UNSC or CONS). In the last row, the number of miles associated with sub-projects in the post-construction phase sums to a different total than the number of miles PG&E has reported externally as being complete. This is for two reasons. First, Table 1 does not include Butte/Community Rebuild sub-projects or miles. Second, PG&E reports miles as they are completed, even if the entire project has not moved to or completed the post-construction phase.

c) *Projects and circuit segments.* We define projects at the circuit segment level, while a sub-project is a job that breaks out the project into phases. Therefore, based on how they are defined, projects are associated with a single circuit segment. Most jobs (sub-projects) fall within a single circuit segment. However, occasionally, jobs may include assets on multiple circuit segments, due to line relocation. In most cases, a job that includes assets on multiple circuit segments will fall into continuous circuit segments. There may be rare exceptions where circuit segments are not continuous, but are geographically near each other—for example, in the case of a double circuit.

Question No. 003:

Project Timeline

a) Please provide an estimate of the time needed to complete an undergrounding project and approximate time needed for each phase of the project.

<u>Response to Question No. 003 Response No. 001:</u>

Sub-project timeline. The time needed to complete each phase of an undergrounding sub-project depends on many factors, including the length of the sub-project, type and number of permits required, etc. In order to reflect up-to-date information on project timing, we analyzed data from sub-projects completed in 2022 and 2023 performed under MAT codes 08W and 3UG, not including Butte/Community Rebuild sub-projects. (Note: the population analyzed for Table 2 differs from the population analyzed for Table 1 in the MAT codes and years analyzed.) We present the results in Table 2.

Table 2 provides a range of statistics demonstrating that, due to individual project characteristics, the time a project spends in each phase can vary greatly, and therefore, a range of values should be considered "typical" for each phase. We note that, as the statistics in Table 2 indicate, project duration is not normally distributed, and a number of projects were in each phase for well beyond the median value. For this reason, we recommend considering a wide range of values "typical." The 25th percentile may represent a reasonable lower bound for most projects. However, due to the number of projects that have longer durations in a given phase, the upper bound of a "typical" project likely falls between the 75th and 95th percentiles.

Table 2. Typical Range of Time Per Undergrounding Project Phase
(Data for 2022 and 2023 Completed Projects as of February 7, 2024)

Phase[1]	# Projects Included in Sample	Duration Spent in Phase (Days)					
		5th Percentile	25th Percentile	Median	Average	75th Percentile	95th Percentile
Scoping	280	20	54	99	127	193	277
Design/estimating	188	18	45	113	137	195	331
Permitting/ dependencies	261	23	49	85	124	165	389
Construction	236	38	97	140	161	210	338
Post-Construction	185	35	55	89	119	138	336
Total Project Completion Time	**185**	**300**	**420**	**610**	**608**	**760**	**996**

Notes: Table 2 includes work performed under MAT codes 08W and 3UG, only sub-projects completed in 2022 and 2023, and does not include Butte/Community Rebuild. The data was cleaned to remove inconsistencies. The statistics shown represent the time spent in a given project phase by a single project. Groups of projects or sub-projects will have overlapping timelines and can be worked in parallel or in series, depending on resource availability. Statistics provided for each project phase are independent of those shown for the other phases—so, for example, a reader would not necessarily gain insight into the 5th percentile of total project duration by adding up all of the durations in the "5th percentile" column. The column Total Project Completion Time shows statistics on the total project completion time from start to finish. These were derived from an analysis of project start and completion dates, rather than by totaling the rows above.

1. SAP status code(s) associated with each phase are the same as in Table 1, and are as follows: Scoping: UNSE; Design/estimating: ESTS, ADER, APPR; Permitting/dependencies: PEND; Construction: UNSC, CONS; Post-construction: DOCC, MAPP, FICL, CLSD.

Question No. 004:

Rebuild Areas

a) How do you define a wildfire rebuild area?
b) What is your process for determining when to underground lines in these areas?

Response to Question No. 004 Response No. 001:

a) *Definition of wildfire rebuild area.* We define a wildfire rebuild area as an area in which electric distribution lines have been damaged by a wildfire and need to be rebuilt to serve customers.
b) *Process for determining when to underground in wildfire rebuild areas.* Undergrounding work in wildfire rebuild areas typically results from the use of a decision tree to determine the type of asset to rebuild. We follow Utility Standard EMER-4004S, Requirements for System Hardening During Emergency Response, and specifically section 4, Hardening Evaluation, and Appendix B, Fire Rebuild Decision Tree, to determine the appropriate approach. Utility Standard EMER-4004S is attached to this data response as *"DRU13015_Q04_Atch 01_EMER-4004S_CONF.pdf."* Please note this attachment contains confidential information.

Requirements for System Hardening During Emergency Response

SUMMARY

This standard describes the required actions that must be taken while performing system hardening during emergency response. These requirements are intended to ensure accurate documentation of system hardening work, updated asset records and fulfillment of Wildfire Mitigation Plan (WMP) commitments.

The specific actions taken to fulfill these requirements may vary due to the unpredictable nature of emergency response.

TARGET AUDIENCE

This standard applies to all PG&E employees who participate in system hardening activities during emergency response. For many of the requirements included in this standard, the Incident Commander (IC) or other members of the Operations Emergency Center (OEC) team will be responsible for the implementation of these requirements.

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REQUIREMENTS

1 Proactive Actions

1.1 WHEN there is potential for a major incident to cause serious or catastrophic damage to PG&E electric distribution facilities,

THEN, Operations Emergency Center (OEC) leadership should begin monitoring impacts to the distribution system and proactively evaluating possible line segmentation strategies and potential hardening opportunities.

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1.1 (continued)

1. Planning Section Chief should contact employees in Geographic Information Systems (GIS) Analytics team to secure daily fire footprint map and distribute to members of OEC, including:

   - Incident Commander
   - Operations Section Chief
   - Assessment Lead
   - Estimating Lead

1.2 Incident Commander must ensure that the following OEC positions are activated for all major incidents which may create potential hardening opportunities.

1. Grid Design Lead - Technical Specialist assigned to the Operations Section

   a. CONSULT with OEC command staff regarding potential hardening opportunities.

   b. SERVE as a liaison between OEC and other teams within Asset Strategy who may provide input regarding alternative hardening options, such as remote grid or customer buyout.

   c. ASSIST other members of OEC with tracking system hardening mileage by circuit and line segment.

2. Quality Control (QC) Lead - Technical Specialist assigned to the Operations Section

   a. ENSURE adequate QC resources are assigned to the incident, based on possible impact to distribution facilities and scope of potential hardening opportunities.

   b. MONITOR progress of hardening work and communicate with Operations Section Chief regarding daily crew deployment strategy. This will ensure QC inspectors are present to perform inspections on the appropriate line segments.

   c. IDENTIFY any issues or concerns that may prevent accurate documentation of system hardening. Unresolved issues must be communicated to the Incident Commander immediately and escalated to the Regional Emergency Center (REC) and/or Emergency Operations Center (EOC), if necessary.

3. Mapping Lead - Technical Specialist assigned to the Planning Section

   a. PROVIDE adequate mapping resources to facilitate job package (see Appendix A) review of all locations prior to event closure.

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1.2.3 (continued)

b. IDENTIFY any incomplete or inaccurate job packages and return them to Operations Section Chief and Estimating Lead for correction.

1.3 Financial guidance for the event, including order numbers, must be distributed to all relevant stakeholders to ensure proper accounting takes place.

1. New system hardening work must be captured under Maintenance Activity Type (MAT) 08W, Work Type 198E.

a. OEC Command Team should consult with System Hardening Program Manager to determine the appropriate number of 08W orders to be created based on scope and location of hardening opportunities.

b. At a minimum, each affected circuit should have an individual 08W PM order. In instances of significant damage to a circuit, it may be appropriate to create hardening orders for individual circuit segments.

c. A separate 08W PM order must be created specifically for all line removals that occur on a circuit.

2. All other capital and expense work should be charged to the appropriate MWC 95 order for each county.

a. Replacement of lines that had already been hardened prior to the fire should be charged to the appropriate MWC 95 order.

2 Assessment Strategy – Major Wildfire

2.1 ALL poles within fire boundary must be assessed. Daily fire footprint map can be used to identify poles needing assessment.

2.2 IF the major incident or event causes widespread damage and/or complete destruction of a circuit,

THEN Public Safety Power Shutoff (PSPS) maps may be used for assessment purposes.

1. GIS or Mapping team may layer fire boundary polygon on top of PSPS maps to assist in identifying poles needing assessment.

2.3 Facility Damage Action for all poles that require replacement must contain the following codes: POLE_BURN_FIRE_REPL.

2.4 Assessment personnel should color code the results of their assessment on a digital or paper map using the following criteria:

1. RED – Pole burned, needs replacement.

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Requirements for System Hardening During Emergency Response

2.4 (continued)

2. GREEN – Pole not damaged.

3. YELLOW – Transformer pole burned and all customer facilities previously served from this location have been destroyed.

4. ORANGE – Other damage not requiring replacement of a pole at this location (e.g. crossarm, conductor, etc.).

> **NOTE**
>
> "Yellow" would only be used to indicate that ALL structures or meters served from the transformer in question were destroyed and customer rebuild will not occur in the short term. If a pole is not highlighted yellow, the assumption will be that there is a customer who will be awaiting service upon repopulation or in the immediate aftermath.

5. Tap lines consisting of all "yellow pins" will be logged as "no restore" in the event Work Location Log. All notifications in the line segment will need to be completed as removals under the 08W removal order.

3 Line Segmentation Strategy

3.1 Clear identification and labeling of line segments that have been damaged or destroyed by a major event is critical to ensure the following:

- Proper evaluation of hardening opportunities
- Quality and accuracy of job packages (see Appendix A) and pole loading
- Strategic deployment of construction resources
- Accurate documentation and record of work

3.2 The specific methodology used to create and label line segments may vary depending on the size, scope and location of damage to a circuit. However, all line segments must adhere to the following requirements:

- All sections of line with damage should be assigned a unique identifier that serves as a label for that specific section of line.
- Mainline vs. tap line must be identified as separate line segments with unique naming conventions (e.g. ML-1 vs TL-1).

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3.2 (continued)

> **NOTE**
>
> 1. The definition of “mainline” is not dependent on wire size but refers to the primary overhead line from which taps originate.
> 2. Unusually large tap lines that extend off of the mainline may also be classified as a mainline segment for the purposes of line segmentation, when appropriate.

1. Mainline segment boundary lines should be placed at device locations, when possible.

2. All line segments should be divided into sizes that will optimize design and construction work but should not exceed 40 poles. Large tap lines should be subdivided to adhere to this limit.

3.3 WHEN a major incident or event causes widespread damage and/or complete destruction of a circuit,

THEN EOC command staff may utilize existing PSPS zones for assessment planning and line segmentation.

1. For example, all mainline poles within Bravo PSPS zone may be considered part of Bravo (or “B”) line segments

2. ASSIGN mainline segment identifiers to be numbered sequentially from source to load (B1, B2, etc.).

3. ASSIGN tap line identifiers (numbered sequentially from source to load) for each tap that originates from a given mainline section.

    a. For every subsequent mainline section, begin assigning new tap line numbers starting at 1.

    b. The resulting tap line naming convention will consist of main line segment number, followed by a tap line segment number. (See Examples 1 and 2)

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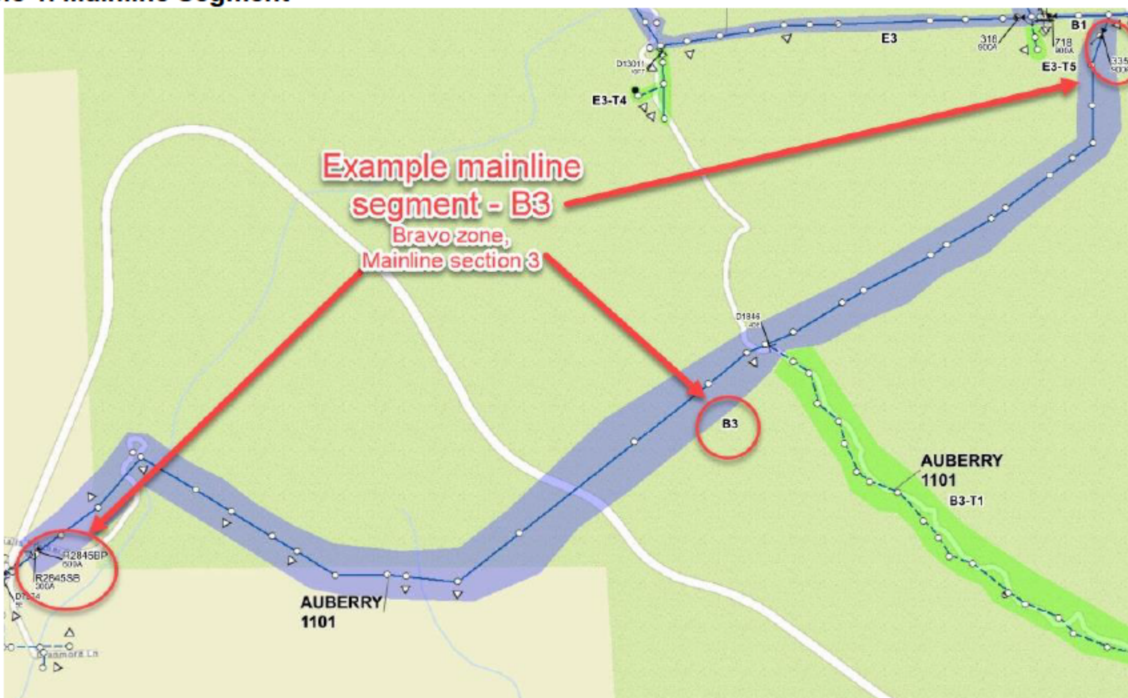
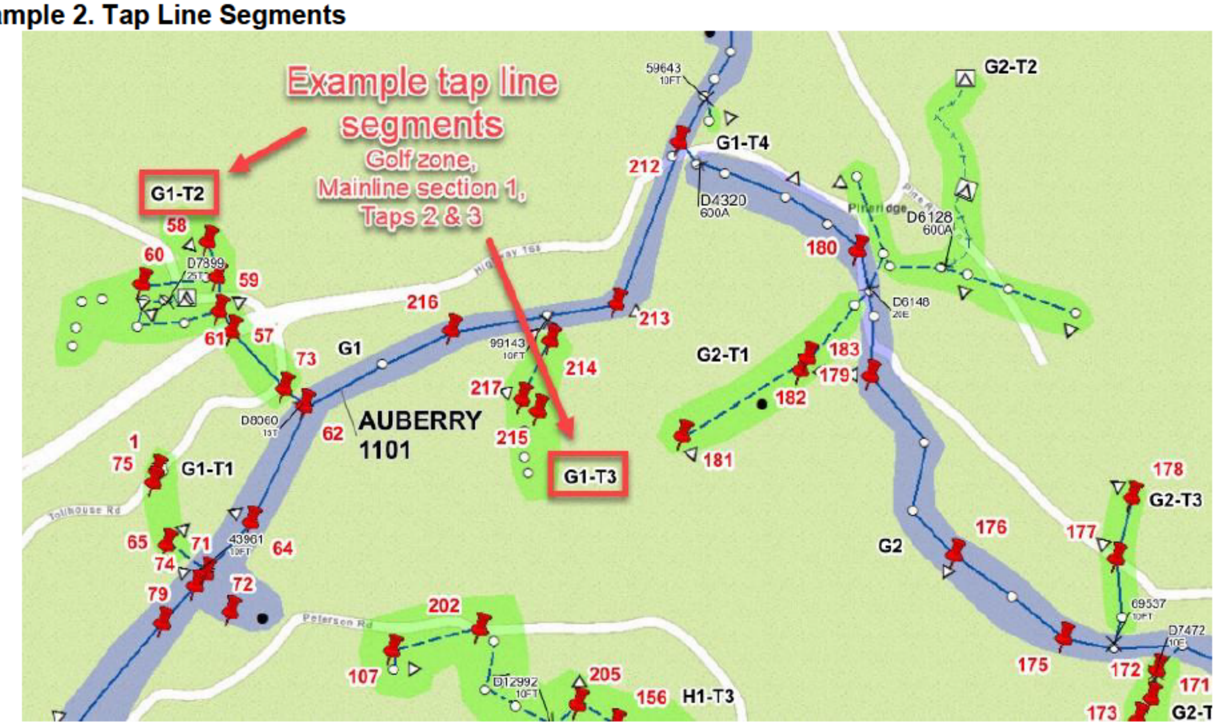
Requirements for System Hardening During Emergency Response

Example 1. Mainline Segment



Example 2. Tap Line Segments



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4 Hardening Evaluation

4.1 All mainline and tap lines damaged during a major incident or event must be evaluated for system hardening opportunities.

4.2 Event Estimating Lead must coordinate with Grid Design Lead to evaluate each line segment for system hardening opportunities.

4.3 Evaluation process must follow Fire Rebuild Decision Tree (see Appendix B) with Incident Commander possessing ultimate decision-making authority.

4.4 Results of hardening evaluation must be documented in Event Work Location Log.

5 Strategic Restoration

5.1 When requesting crew resources, Incident Commander must be aware of additional lead time needed to evaluate all line segments for hardening opportunities. Additionally, job packages (see Appendix A) for hardening work may take additional time to design.

5.2 The proactive development of a coordinated line segmentation strategy will allow Incident Commander and Operations Section Chief to strategically deploy crews using a Task Force Lead (TFL) system with TFL ownership of assigned line segments.

6 Documentation and Mapping

6.1 A copy of each job package that includes a system hardening construction drawing must be distributed to QC Lead.

6.2 Construction personnel must ensure that pole locations and span lengths constructed are accurate and match those shown on the construction drawing prior to job package being signed and turned in for completion.

6.3 IF span lengths constructed in field differ from span lengths as designed in job package,

THEN crew foreman must:

- Contact estimating lead to verify pole loading and update pole loading calculation (PLC).
- Redline as-built drawing to reflect actual span lengths.

6.4 ALL job packages must be reviewed by mapping personnel PRIOR to closure of OEC.

1. Mapping must reject job packages with inconsistent or incomplete documentation.
2. Rejected job packages should be reviewed by Operations Section Chief and Estimating Lead for correction and resubmittal.

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6.4 (continued)

3. Mapping must track approved job packages (see Appendix A) on the Major Event Work Location Log.

6.5 Event Estimating Lead is responsible to ensure that all redlined job packages are validated for compliance with pole loading standards. Operations Section Chief must be notified immediately of any redline changes made in the field that exceed pole loading limitations or are not compliant with construction standards.

END of Requirements

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DEFINITIONS

BASE CAMP: Location where primary Logistics functions for an incident are coordinated and administered. An incident name or other designator is added to the words “Base Camp.” The Incident Command Post may be co-located with the base camp.

EMERGENCY OPERATIONS CENTER (EOC): Pre-designated facility established by an agency or jurisdiction to coordinate overall agency or jurisdictional response and support to an emergency.

INCIDENT COMMAND SYSTEM (ICS): The command structure used in major emergency activations at EOC, OEC and DSR. It is a standardized management tool for meeting the demands of small or large emergency situations.

INCIDENT COMMANDER (IC): Individual responsible for the management of all incident operations at the incident site.

INCIDENT MANAGEMENT TEAM (IMT): Incident Commander and appropriate Command and General Staff personnel assigned to an incident.

OPERATIONS EMERGENCY CENTER (OEC): Provides oversight and support at a divisional level. Directs and coordinates the personnel necessary to assess damages, secure hazardous situations, restore service, and communicate status information internally and externally. OECs report to their region’s Region Emergency Center (REC).

REGIONAL EMERGENCY CENTER (REC): Provides oversight and support to the OEC(s) at a regional level. As an event escalates, the REC becomes the point of contact for information and managing escalated OEC(s) issues. When PG&E’s Emergency Operations Center (EOC) is activated, the REC communicates operational status, resource requests, and logistical needs to the EOC.

IMPLEMENTATION RESPONSIBILITIES

The assigned Incident Commander is ultimately responsible for the implementation of this standard, as it applies to a specific event.

GOVERNING DOCUMENT

NA

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Records and Information Management:

PG&E records are company assets that must be managed with integrity to ensure authenticity and reliability. Each Line of Business (LOB) must manage Records and Information in accordance with the Enterprise Records and Information (ERIM) Policy, Standards and Enterprise Records Retention Schedule (ERRS). Each Line of Business (LOB) is also responsible for ensuring records are complete, accurate, verifiable and can be retrieved upon

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request. Refer to GOV-7101S, "Enterprise Records and Information Management Standard" for further records management guidance or contact ERIM at Enterprise_RIM@pge.com."

REFERENCE DOCUMENTS

Developmental References:

NA

Supplemental References:

EMER-01, "Emergency Preparedness and Response Policy"

EMER-3001M, "Company Emergency Response Plan (CERP)"

EMER-3002M, "Electric Annex"

TD-4461M, "As-Built Redline Handbook"

APPENDICES

Appendix A, High Lever Job Package Flow Chart

Appendix B, Fire Rebuild Decision Tree

ATTACHMENTS

NA

DOCUMENT RECISION

NA

DOCUMENT APPROVER

[redacted], Sr. Director, Major Programs & Projects Delivery

DOCUMENT OWNER

[redacted], Principal Program Manager, Wildfire Work Delivery

DOCUMENT CONTACT

[redacted], Manager, Grid Design

[redacted], Manager, Central Design

[redacted], Principal Program Manager, Wildfire Work Delivery

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Requirements for System Hardening During Emergency Response

REVISION NOTES

Where?	What Changed?
NA	New Standard

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Appendix A, High Lever Job Package Flow Chart
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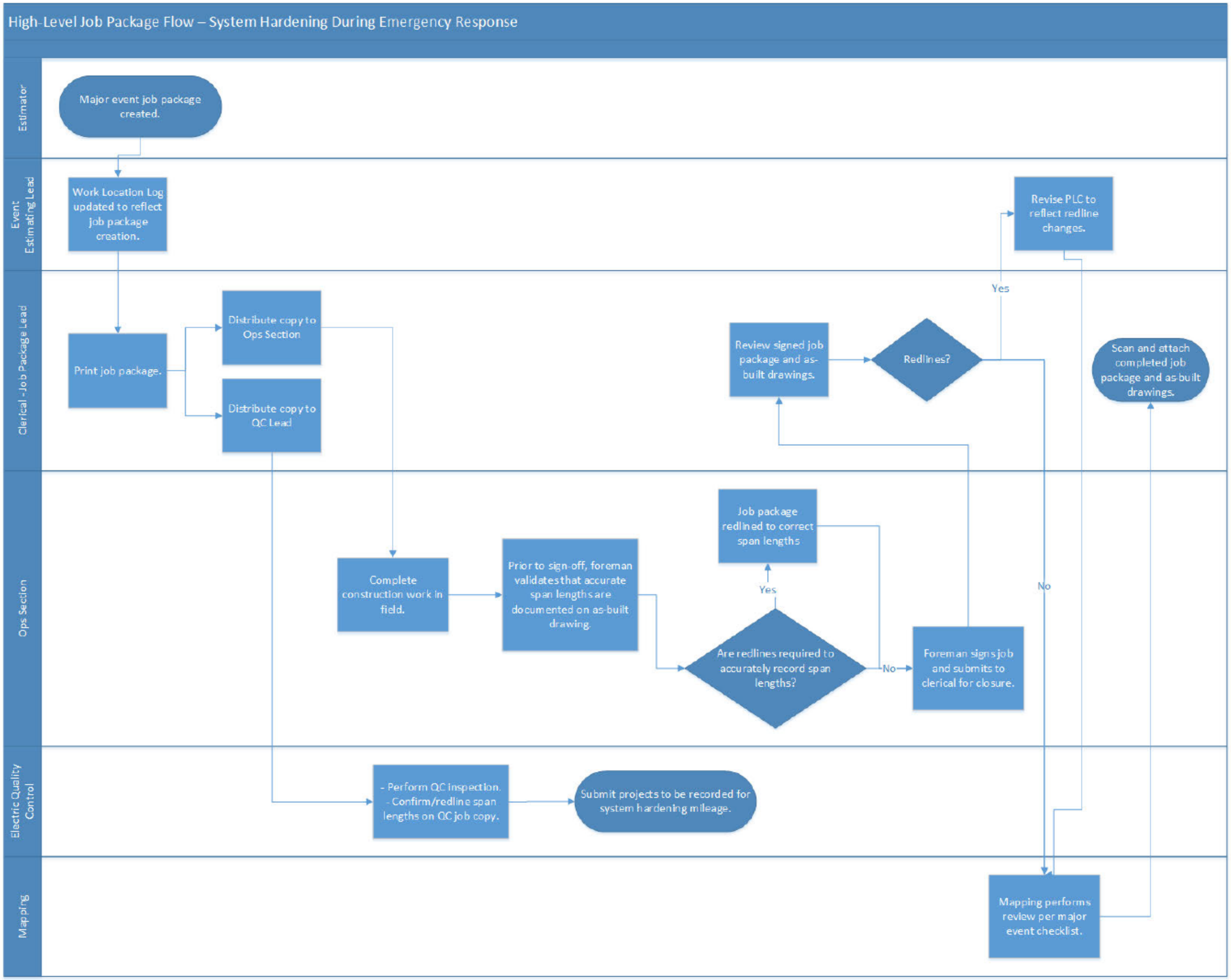

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Appendix B, Fire Rebuild Decision Tree

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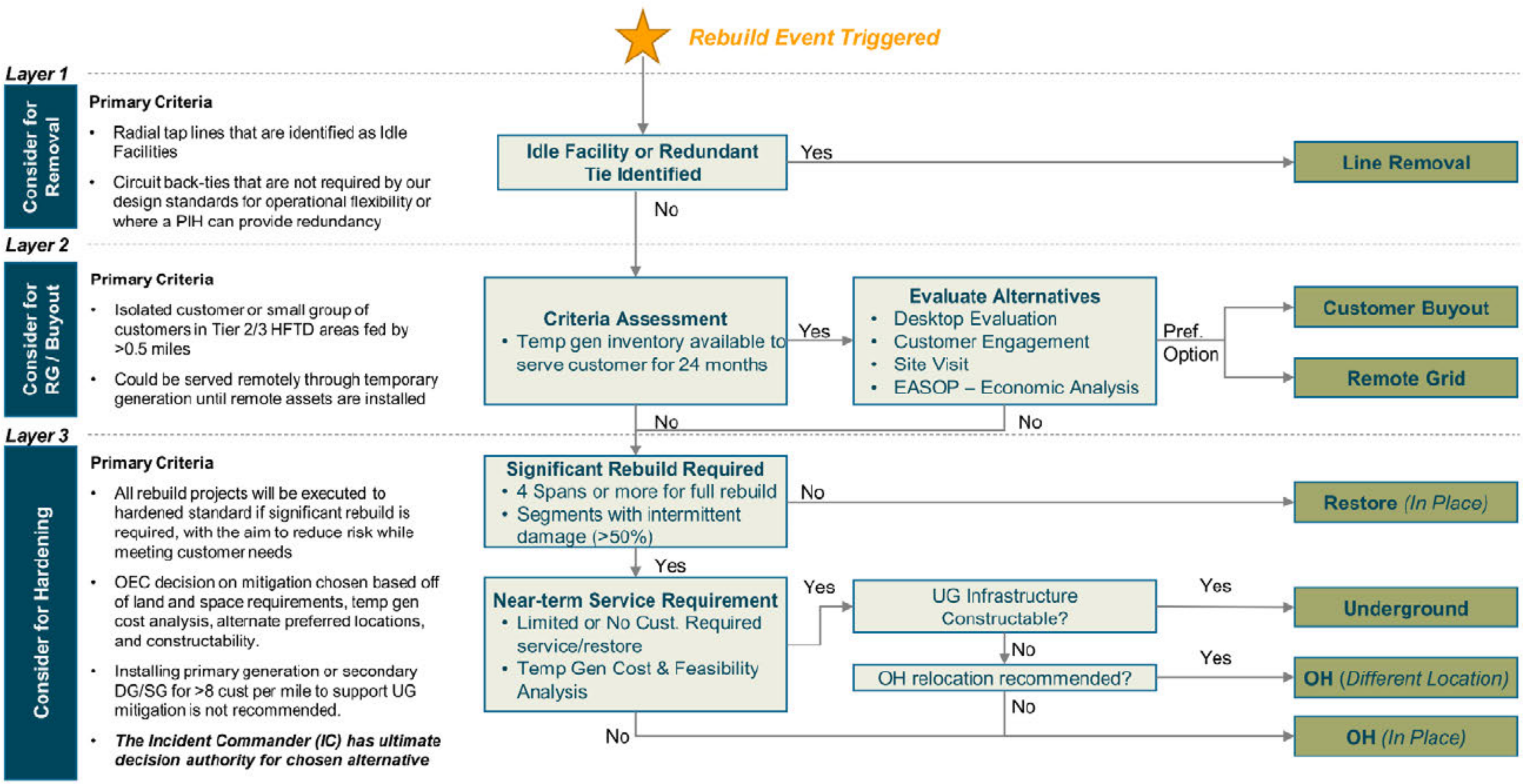

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